NORTHERN OIL & GAS, INC.
Form 10-Q
August 09, 2011

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

T QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2011

£ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE EXCHANGE ACT

For the transition period from ____________ to____________

Commission File No. 001-33999

NORTHERN OIL AND GAS, INC.
(Exact name of Registrant as specified in its charter)

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

315 Manitoba Avenue – Suite 200
Wayzata, Minnesota 55391
(Address of Principal Executive Offices)

(952) 476-9800
(Registrant's Telephone Number)

N/A
(Former name, former address and former fiscal year, if changed since last report)

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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act:

Large Accelerated Filer £ Accelerated Filer T

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

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

As of August 8, 2011, there were 63,138,424 shares of our common stock, par value $0.001, outstanding.

GLOSSARY OF TERMS

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

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

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

“Bbl” – barrel or barrels.

“BOE” – barrels of crude oil equivalent.

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

“MBbl” – thousand barrels.

“MBoe” – thousand barrels of crude oil equivalent.

“Mcf” – thousand cubic feet of gas.

“Mcfe” – thousand cubic feet of gas equivalent.

“MMBbls” – million barrels.

“MMBoe” – million barrels of crude oil equivalent.

“MMcf” – million cubic feet of gas.

“MMcfe” – million cubic feet of gas equivalent.

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

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

Terms used to describe our interests in wells and acreage:

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

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

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

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

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

"Gross well" is a well in which we own a working interest.

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

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

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

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

“Productive well” is an exploratory or a development well that is not a dry hole.

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

NORTHERN OIL AND GAS, INC.
FORM 10-Q

June 30, 2011

C O N T E N T S

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements.

NORTHERN OIL AND GAS, INC.
CONDENSED BALANCE SHEETS
JUNE 30, 2011 AND DECEMBER 31, 2010

ASSETS
(UNAUDITED)

	June 30, 2011	December 31, 2010
CURRENT ASSETS		
Cash and Cash Equivalents	$77,379,376	$152,110,701
Trade Receivables	35,586,298	22,033,647
Prepaid Drilling Costs	15,755,429	13,225,650
Prepaid Expenses	518,841	345,695
Other Current Assets	211,015	475,967
Short - Term Investments	-	39,726,700
Deferred Tax Asset	6,203,000	5,100,000
Total Current Assets	135,653,959	233,018,360
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	267,625,123	158,846,475
Unproved	185,767,402	136,135,163
Other Property and Equipment	2,552,891	2,479,199
Total Property and Equipment	455,945,416	297,460,837
Less - Accumulated Depreciation and Depletion	37,504,043	22,152,356
Total Property and Equipment, Net	418,441,373	275,308,481
DEBT ISSUANCE COSTS	1,186,783	1,367,124
Total Assets	$555,282,115	$509,693,965
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$56,416,606	$48,500,204
Accrued Expenses	1,440,211	2,829
Derivative Liability	14,279,978	11,145,319
Other Liabilities	18,574	18,574
Total Current Liabilities	72,155,369	59,666,926
LONG-TERM LIABILITIES		
Revolving Credit Facility	-	-
Derivative Liability	1,764,445	5,022,657

Other Noncurrent Liabilities	681,133	477,900
Total Long-Term Liabilities	2,445,578	5,500,557

	June 30, 2011	December 31, 2010
DEFERRED TAX LIABILITY	19,141,000	9,167,000
Total Liabilities	93,741,947	74,334,483
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value $.001; 5,000,000Authorized, No Shares Outstanding	-	-
Common Stock, Par Value $.001; 95,000,000 Authorized, (6/30/2011 -63,138,424 Shares Outstanding and 12/31/2010 - 62,129,424 Shares Outstanding)	63,138	62,129
Additional Paid-In Capital	440,772,915	428,484,092
Retained Earnings	21,134,250	7,759,192
Accumulated Other Comprehensive Loss	(430,135)	(945,931)
Total Stockholders' Equity	461,540,168	435,359,482
Total Liabilities and Stockholders' Equity	$555,282,115	$509,693,965

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

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NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF OPERATIONS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2011 AND 2010
(UNAUDITED)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
REVENUES				
Oil and Gas Sales	$35,481,664	$11,664,873	$62,523,285	$20,033,720
(Loss) Gain on Settled Derivatives	(5,608,231)	303,919	(8,870,287)	126,936
Mark-to-Market Gain (Loss) of Derivative Instruments	20,848,232	4,251,199	(430,397)	3,260,383
Other Revenue	104,433	11,782	130,246	32,248
Total Revenues	50,826,098	16,231,773	53,352,847	23,453,287
OPERATING EXPENSES				
Production Expenses	2,615,546	561,427	4,631,902	893,757
Production Taxes	3,311,037	1,024,277	5,926,901	1,670,143
General and Administrative Expense	2,749,418	1,911,543	6,040,007	3,618,511
Depletion of Oil and Gas Properties	8,349,600	2,600,836	15,213,079	4,484,441
Depreciation and Amortization	70,295	26,267	138,608	50,897
Accretion of Discount on Asset Retirement Obligations	7,794	9,215	12,524	12,752
Total Expenses	17,103,690	6,133,565	31,963,021	10,730,501
INCOME FROM OPERATIONS	33,722,408	10,098,208	21,389,826	12,722,786
OTHER INCOME (EXPENSE)	(229,508)	(144,342)	537,532	(232,290)
INCOME BEFORE INCOME TAXES	33,492,900	9,953,866	21,927,358	12,490,496
INCOME TAX PROVISION	13,060,000	3,833,000	8,552,300	4,810,000
NET INCOME	$20,432,900	$6,120,866	$13,375,058	$7,680,496
Net Income Per Common Share - Basic	$0.33	$0.12	$0.22	$0.16
Net Income Per Common Share - Diluted	$0.33	$0.12	$0.22	$0.16
Weighted Average Shares Outstanding – Basic	61,686,463	49,934,409	61,586,603	47,032,602
Weighted Average Shares Outstanding - Diluted	62,053,888	50,609,944	62,028,292	47,593,962

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

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NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF CASH FLOWS
FOR THE SIX MONTHS ENDED JUNE 30, 2011 AND 2010
(UNAUDITED)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$13,375,058	$7,680,496
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depletion of Oil and Gas Properties	15,213,079	4,484,441
Depreciation and Amortization	138,608	50,897
Amortization of Debt Issuance Costs	180,341	280,768
Accretion of Discount on Asset Retirement Obligations	12,524	12,752
Deferred Income Taxes	8,550,000	4,810,000
Net (Gain) Loss on Sale of Available for Sale Securities	(215,092)	197,556
Unrealized Loss (Gain) on Derivative Instruments	430,397	(3,260,383)
Amortization of Deferred Rent	(9,287)	(9,287)
Share - Based Compensation Expense	3,363,345	2,006,369
Changes in Working Capital and Other Items:		
Increase in Trade Receivables	(13,552,651)	(4,286,731)
Increase in Prepaid Expenses	(173,146)	(337,765)
Decrease (Increase) in Other Current Assets	264,952	(71,078)
Increase in Accounts Payable	7,916,402	3,567,953
Decrease (Increase) in Accrued Expenses	158	(138,281)
Net Cash Provided By Operating Activities	35,494,688	14,987,707
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of Other Equipment and Furniture	(73,692)	(1,753,791)
Increase in Prepaid Drilling Costs	(2,529,779)	(4,977,412)
Proceeds from Sale of Oil and Gas Properties	5,027,162	237,877
Purchase of Available for Sale Securities	(18,381,690)	-
Proceeds from Sale of Available for Sale Securities	58,606,328	25,890,901
Purchase of Oil and Gas Properties and Development Capital Expenditures	(154,374,342)	(51,636,851)
Net Cash Used For Investing Activities	(111,726,013)	(32,239,276)
CASH FLOWS FROM FINANCING ACTIVITIES		
Payments on Line of Credit	-	(834,492)
Advances on Revolving Credit Facility	-	5,300,000
Payments on Revolving Credit Facility	-	(5,300,000)
Repayment of Subordinated Notes	-	(100,000)
Debt Issuance Costs Paid	-	(379,400)
Proceeds from Exercise of Warrants	1,500,000	-
Proceeds from Issuance of Common Stock - Net of Issuance Costs	-	82,500,000
Net Cash Provided by Financing Activities	1,500,000	81,186,108

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	Six Months Ended June 30, 2011	2010
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(74,731,325)	63,934,539
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	152,110,701	6,233,372
CASH AND CASH EQUIVALENTS – END OF PERIOD	$77,379,376	$70,167,911
Supplemental Disclosure of Cash Flow Information		
Cash Paid During the Period for Interest	$-	$125,135
Cash Paid During the Period for Income Taxes	$-	$-
Non-Cash Financing and Investing Activities:		
Purchase of Oil and Gas Properties through Issuance of Common Stock	$-	$5,698,337
Payment of Compensation through Issuance of Common Stock	$12,227,060	$4,224,114
Capitalized Asset Retirement Obligations	$199,996	$69,802

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

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS
JUNE 30, 2011
(Unaudited)

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the "Company," "our," "we," "us" and words of similar import) is a growth-oriented independen energy company engaged in the acquisition, exploration, exploitation and development of crude oil and natural gas properties. The Company's common stock trades on the NYSE Amex Equities Market under the symbol "NOG".

The Company acquires interests in crude oil and natural gas acreage and drilling projects, primarily within the Williston Basin Bakken Shale formation. The Company is continuing to develop its substantial leasehold acreage in the Bakken play and will target additional opportunities in the Bakken and Three Forks play. The Company owns working interests in wells, and does not lease land to operators. Management believes the Company's experience gained by participating as a non-operating partner has given the Company valuable data on completions and will help its operating partners control well costs and enhance results as the Company continues to develop its higher working interest sections in the remainder of 2011 and beyond.

The Company participates on a heads up basis proportionate to its working interest in declared drilling units. As of June 30, 2011, the Company's principal assets included approximately 158,046 net acres located in the northern region of the United States, of which the Company held leasehold interests on approximately 155,353 net mineral acres in the Williston Basin targeting the Bakken and Three Forks formations. The Company continues to expand its position through aggressive acquisition and leasing programs.

The Company's land acquisition and field operations, along with various other services, are primarily outsourced through the use of consultants and drilling partners. The Company will continue to retain independent contractors to assist in operating and managing the prospects and other administrative functions. With the additional acquisition of crude oil and natural gas properties, the Company intends to continue to use both in-house employees and outside consultants to develop and exploit its leasehold interests.

As an independent crude oil and natural gas producer, the Company's revenue, profitability and future rate of growth are substantially dependent on prevailing prices of crude oil and natural gas. A substantial or extended decline in crude oil or natural gas prices could have a material effect on the Company's financial position, results of operations, cash flows and access to capital, and on the quantities of natural gas and crude oil reserves that can be economically produced.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The financial information included herein is unaudited. The balance sheet as of December 31, 2010 has been derived from the Company's audited financial statements as of December 31, 2010. However, such information includes all adjustments (consisting of normal recurring adjustments and change in accounting principles), which are in the opinion of management, necessary for a fair presentation of financial position, results of operations and cash flows for the interim periods. The results of operations for interim periods are not necessarily indicative of the results to be expected for an entire year.

Certain information, accounting policies, and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted in this Form 10-Q pursuant to certain rules and regulations of the Securities and Exchange Commission ("SEC"). The financial statements should be read in conjunction with the audited financial statements for the year ended December 31, 2010, which were included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

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

Short-Term Investments

All United States Treasuries that 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. The realized gains and losses related to these securities are included in Other Income (Expense) in the condensed statements of operations.

Other Property and Equipment

Property and equipment that are not crude oil and natural gas properties are recorded at cost and depreciated using the straight-line method over their estimated useful lives of three to fifteen years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than crude oil and natural gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The Company has not recognized any impairment losses on non-crude oil and natural gas long-lived assets. Depreciation expense was $138,608 and $50,897 for the six months ended June 30, 2011 and 2010 respectively.

Debt Issuance Costs

In February 2009, the Company entered into a revolving credit facility with CIT Capital USA, Inc. ("CIT") (See Note 8). 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 exercised these warrants at a price of $5.00 per share in January 2011. The initial total amount capitalized for Debt Issuance Costs was $1,670,000 related to the original agreement with CIT. In May 2009, the Company amended the revolving credit facility with CIT to allow for additional borrowings. The Company incurred and capitalized $216,414 of direct costs related to this amendment.

In May 2010, the Company completed an assignment of its revolving credit facility to Macquarie Bank Limited ("Macquarie") from CIT. In connection with the assignment, the Company and Macquarie entered into an Amended and Restated Credit Agreement governing the credit facility. The Company incurred and capitalized $386,179 of direct costs related to this assignment and amendment.

The debt issuance costs are being amortized over the term of the facility.

The amortization of debt issuance costs for the six months ended June 30, 2011 and 2010 was $180,341 and $280,768, respectively.

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 Asset Retirement Obligation is included in Other Noncurrent Liabilities on the condensed balance sheet. 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 Natural Gas Balancing

The Company recognizes crude oil and natural gas revenues from its interests in producing wells when production is delivered to, and title has transferred to, the purchaser and to the extent the selling price is reasonably determinable. The Company uses the sales method of accounting for natural gas balancing of natural gas production and would recognize a liability if the existing proven reserves were not adequate to cover the current imbalance situation. As of June 30, 2011 and December 31, 2010, the Company's natural gas production was in balance, meaning its cumulative portion of natural gas production taken and sold from wells in which it has an interest equaled its entitled interest in natural gas production from those wells.

Stock-Based Compensation

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

Income Taxes

The Company accounts for income taxes under FASB ASC 740-10-30. Deferred income tax assets and liabilities are determined based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Accounting standards require the consideration of a valuation allowance for deferred tax assets if it is “more likely than not” that some component or all of the benefits of deferred tax assets will not be realized. No valuation allowance has been recorded as of June 30, 2011 and December 31, 2010.

Stock Issuance

The Company records the stock-based compensation awards issued to non-employees and other external entities for goods and services at either the fair market value of the goods received or services rendered or the instruments issued in exchange for such services, whichever is more readily determinable, using the measurement date guidelines enumerated in FASB ASC 505-50-30.

Net Income Per Common Share

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

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three and six months ended June 30, 2011 and 2010 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Weighted average common shares outstanding - basic	61,686,463	49,934,409	61,586,603	47,032,602
Plus: Potentially dilutive common shares				
Stock options, warrants, and restricted stock	367,425	675,534	441,689	561,359
Weighted average common shares outstanding - diluted	62,053,888	50,609,944	62,028,292	47,593,962
Stock options, warrants, and restricted stock excluded from EPS due to the anti-dilutive effect	-	-	-	-

Full Cost Method

The Company follows the full cost method of accounting for crude oil and natural gas operations whereby all costs related to the exploration and development of crude oil and natural gas properties are initially capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition, and exploration activities. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to the production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred. The Company capitalized $9,604,131 and $2,771,704 of internal costs and $0 and $59,711 of interest for the six months ended June 30, 2011and 2010, respectively.

As of June 30, 2011, the Company held leasehold interests on acreage in Sheridan County, Montana with primary targets including the Red River and Mission Canyon. The Company held leasehold interest on acreage in Billings, Burke, Divide, Dunn, Golden Valley, McKenzie, McLean, Mercer, Mountrail, Stark and Williams Counties, North Dakota and in Richland and Roosevelt Counties, Montana targeting the Bakken and Three Forks formations as well as acreage in Yates County, New York that is prospective for Trenton/Black River, Marcellus and Queenstown-Medina natural gas production.

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. The Company received $5,027,162 of proceeds from property sales in the six months ended June 30, 2011, which was credited to the full cost pool.

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 are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by independent petroleum engineers on an annual basis. In interim periods, the Company's management estimates depletion taking into account estimated additional reserves, future development costs, amongst other variables. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and full cost ceiling calculations. For the six months ended June 30, 2011, the Company included $5,550,022 of costs related to expired leases in, Richland County Montana, Burke County, Dunn County and Mountrail County North Dakota and Yates County, New York, which costs are subject to the depletion calculation. Of the 17,607 net acres (34,846 gross acres) that expired in the six months ended June 30, 2011, 12,349 net acres were prospective for the Bakken and Three Forks formations that the Company did not renew, extend or save by any other lease savings clause. The remainder of the acreage consisted of 5,258 net acres in Yates County, New York that the company decided not to renew, extend or save by any other lease savings clause.

Capitalized costs of crude oil and natural gas properties (net of related deferred income taxes) may not exceed an amount equal to the present value, discounted at 10% per annum, of the estimated future net cash flows from proved crude oil and natural gas reserves plus the cost of unproved properties (adjusted for related income tax effects). Should capitalized costs exceed this ceiling, impairment is recognized. The present value of estimated future net cash flows is computed by applying the 12-month average price of crude oil and natural gas to estimated future production of proved crude oil and natural gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions. Such present value of proved reserves' future net cash flows excludes future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet. Should this comparison indicate an excess carrying value, the excess is charged to earnings as an impairment expense. As of June 30, 2011, the Company has not realized any impairment of its properties.

Use of Estimates

The preparation of these condensed 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 crude oil and natural gas reserve volumes, future development costs, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, fair value of certain investments, and deferred income taxes. Actual results may differ from those estimates.

Reclassifications

Certain reclassifications have been made to prior years' reported amounts in order to conform with the current period presentation. In prior periods the Company separately indentified share based compensation on its condensed statement of operations. These amounts have been reclassified to be included in general and administrative expense. These reclassifications did not impact the Company's 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 crude 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 crude oil or natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. The Company has, and may continue to use exchange traded futures contracts and option contracts to hedge the delivery price of crude oil at a future date.

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 13 for a description of the derivative contracts which the Company executed during 2011, and 2010.

Derivatives, historically, were recorded on the balance sheet at fair value and changes in the fair value of derivatives were recorded each period in Current Earnings or Other Comprehensive Income, depending on whether a derivative was designated as part of a hedge transaction and, if it was, depending on the type of hedge transaction. The Company's derivatives historically consisted primarily of cash flow hedge transactions in which the Company was hedging the variability of cash flows related to a forecasted transaction. Period to period changes in the fair value of derivative instruments designated as cash flow hedges were reported in Accumulated Other Comprehensive Income (Loss) and reclassified to earnings in the periods in which the hedged item impacts earnings. The ineffective portion of the cash flow hedges were reflected in current period earnings as gain or loss from derivatives. Gains and losses on derivative instruments that did not qualify for hedge accounting were included in income or loss from derivatives in the period in which they occur. The resulting cash flows from derivatives were reported as cash flows from operating activities.

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 gains and losses are recorded to Gain (Loss) on Settled Derivatives and unrealized gains or losses are recorded to Mark-to-Market of Derivative Instruments on the Condensed Statement of Operations rather than as a component of Accumulated Other Comprehensive Income (Loss) or Other Income (Expense).

New Accounting Pronouncements

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

NOTE 3 SHORT-TERM INVESTMENTS

All United States Treasuries that are included in short-term investments are considered available-for-sale and are carried at fair value. The short-term investments are considered current assets due to their maturity term or the Company's ability and intent to use them to fund current operations. The unrealized gains and losses related to these securities are included in Accumulated Other Comprehensive Income (Loss). The realized gains and losses related to these securities are included in Other Income (Expense) in the condensed statements of operations. For the six months ended June 30, 2011, the Company realized gains of $215,092 on the sale of short-term investments. For the six months ended June 30, 2010, the Company realized losses of $197,556 on the sale of short-term investments.

The Company has no short-term investments as of June 30, 2011.

The following is a summary of the Company's short-term investments as of December 31, 2010:

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

NOTE 4 CRUDE OIL AND NATURAL GAS PROPERTIES

The value of the Company's crude oil and natural gas properties consists of all acreage acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Each of these costs contributed to the Company's approximate $158 million increase in crude oil and natural gas properties during the six months ended June 30, 2011.

Acquisitions

For the six months ended June 30, 2011, the Company completed acreage acquisitions involving properties spanning across the following counties of North Dakota: Billings, Burke, Divide, Dunn, McKenzie, Mountrail, Stark and Williams and Richland and Roosevelt counties of Montana. The Company generally values acreage subject to near-term drilling activities on a lease-by-lease basis because it believes each lease's contribution to a subject spacing unit is best assessed on that basis if development timing is sufficiently clear. Consistent with that approach, the majority of the Company's acreage acquisitions involve properties that are "hand-picked" by the Company on a lease-by-lease basis for their contribution to a well expected to be spud in the near future, and the subject leases are then aggregated to complete one single closing with the transferor. As such, the Company generally views each acreage assignment from brokers, landmen and other parties as involving several separate acquisitions combined into one closing with the common transferor for convenience. However, in certain instances an acquisition may involve a larger number of leases presented by the transferors as a single package without negotiation on a lease-by-lease basis. In those instances, the Company still reviews each lease on a lease-by-lease basis to ensure that the package as a whole meets its acquisition criteria and drilling expectations.

Divestitures

In January, 2010, the Company's board of directors approved an arrangement whereby the Company efficiently divests minimal working interests in wells. In March 2010, the Company entered into an agreement with a private unrelated company, whereby the Company has the option (but not the obligation) to sell minimal wellbore interests in any drilling unit where the Company's interest constitutes less than 0.0050 working interest in a well. The Company retains the underlying leasehold interest and only assigns the wellbore interest. Through this arrangement, the Company has divested wellbores with an average working interest of approximately 0.0025 of one net well for a total aggregate divestiture of 0.23 of one net well. The Company believes the divestiture of these minimal working interests creates value by avoiding the administrative, reserve engineering and accounting costs that would be associated with these minimal interests. The proceeds from sales under the agreement were applied to reduce the capitalized costs of oil and gas properties.

In November 2009, the Company agreed to participate in the exploration and development of Slawson Exploration Company, Inc.'s ("Slawson") Anvil project in Roosevelt and Sheridan Counties, Montana and Williams County, North Dakota. In April 2011, the Company sold its interest in the Anvil project for $4,960,784. As of the date of sale, the Company's cost basis in the Anvil project was $1,785,007. The Company sold its interest in the project along with Slawson, who also desired to sell its entire interest in the project. Slawson had drilled and completed one well in the project area prior to the divestiture – the Mayhem #1-19H well – and the Company retained its interest in that wellbore in connection with the divestiture. The proceeds from the sale were applied to reduce the capitalized costs of oil and gas properties.

Unproved Properties

The Company's unproved properties not being amortized comprise of approximately 126,614 net acres of undeveloped leasehold interests. The Company believes that the majority of its unproved costs will become subject to depletion within the next five years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of its reserves.

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

The Company had 161 gross (15.02 net) wells drilling, awaiting completion or completing as of June 30, 2011. All properties that are not classified as proven properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion. Once a property is classified as proven, all associated acreage and drilling costs are subject to depletion.

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

As of June 30, 2011, the Company was participating in three defined drilling projects with Slawson covering an aggregate of 15,065 net acres of leasehold interests held by the Company. The Windsor project area includes approximately 3,323 net acres held by the Company, primarily located in Mountrail and surrounding counties of North Dakota. The South West Big Sky project includes approximately 3,380 total net acres held by the Company in Richland County of Montana. The Lambert project includes approximately 8,362 net acres held by the Company in Richland County of Montana.

NOTE 5 PREFERRED AND COMMON STOCK

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

In January 2011, CIT exercised the 300,000 warrants that were issued as part of the initial revolving credit facility (Note 8). Total proceeds from the exercise of these warrants were $1.5 million.

In January 2011, the Company issued 2,000 shares of Common Stock to two employees of the Company as compensation for their services. The shares were fully vested on the date of the grant. The fair value of the stock issued was $55,960 or $27.98 per share, the market value of a share of common stock on the date the stock was issued. The entire amount of this stock award was expensed in the six months ended June 30, 2011.

In January 2011, the Company issued an aggregate of 15,265 shares of Common Stock to four executives of the Company as compensation for their services. The shares were fully vested on the date of the grant. The fair value of the stock issued was $427,115 or $27.98 per share, the market value of a share of common stock on the date the stock was issued. The entire amount of this stock award was expensed in the six months ended June 30, 2011.

In January 2011, the Company issued 100,000 shares of Common Stock to two executives of the Company as partial consideration for the amendment and restatement of their employment agreements, which included the extension of non-compete terms from one to three years along with various other modifications. The executives were fully vested in the shares on the date of the grant. The fair value of the stock issued was $2,798,000 or $27.98 per share, the market value of a share of common stock on the date the stock was issued. The entire amount of this stock award was expensed in the six months ended June 30, 2011.

In April 2011, the Company issued 1,000 shares of Common Stock to an employee of the Company as compensation for their services. The shares were fully vested on the date of the grant. The fair value of the stock issued was $23,760 or $23.76 per share, the market value of a share of common stock on the date the stock was issued. The entire amount of this stock award was expensed in the six months ended June 30, 2011.

In May 2011, the Company's board of directors approved a stock repurchase program to acquire up to $150 million shares of the Company's outstanding common stock. The stock repurchase program will allow the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions. The Company has not made any repurchases under this program to date.

As of June 30, 2011, the Company had accrued bonuses of approximately $1.4 million based on the year to date results of operations in comparison to year-end bonus attainment expectations. This includes, but is not limited to operational metrics, such as increased well count, increased proven reserves, additional strategic acreage acquisitions, and meeting various other targets as established by the Company's Compensation Committee. Management anticipates these bonuses will be paid in the fourth quarter of 2011 through the issuance of shares of common stock. The accrued bonuses as of June 30, 2011, are an estimate and are considered discretionary based on 2011 operations. The Company's Compensation Committee has approved a plan to grant bonuses and the bonus accrual is based on that plan, but the June 30, 2011 bonus accrual balance has not been approved by the Compensation Committee. The Company expensed $422,782 in share-based compensation related to this bonus accrual in the six months ended June 30, 2011. The remainder of bonus was capitalized into the full cost pool. As of June 30, 2010, the Company had accrued bonuses of approximately $1.8 million, of which $801,775 were expensed in share-based compensation. The bonuses accrued as June 30, 2010 were paid in the fourth quarter of 2010 through the issuance of shares of common stock.

NOTE 6 RELATED PARTY TRANSACTIONS

The Company previously purchased leasehold interests from Gallatin Resources, LLC ("Gallatin") in 2007. During the first six months of 2011, the Company paid Gallatin a total of $2,185 related to previously acquired leasehold interests. Carter Stewart, one of the Company's directors, owns a 25% interest in Gallatin. Legal counsel for Gallatin informed the Company that Mr. Stewart does not have the power to control Gallatin Resources because each member of Gallatin has the right to vote on matters in proportion to their respective membership interest in the company and company matters are determined by a vote of the holders of a majority of membership interests. Further, Mr. Stewart is neither an officer nor a director of Gallatin. As such, Mr. Stewart does not have the ability to individually control company decisions for Gallatin.

The Company had a securities account with Morgan Stanley Smith Barney that was managed by Kathleen Gilbertson, a financial advisor with that firm who is the sister of the Company's president and Director, Ryan Gilbertson. The Company closed this account on August 4, 2011.

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

NOTE 7 STOCK OPTIONS/STOCK-BASED COMPENSATION AND WARRANTS

On April 26, 2011, the board of directors approved an amendment and restatement of the Northern Oil and Gas, Inc. 2009 Equity Incentive Plan (the "Plan"), which was approved at the annual meeting of shareholders. An additional 1,000,000 shares were authorized for grant under the Plan, resulting in an aggregate of 4,000,000 shares authorized for past and future grants under the Plan. The Plan is intended to provide a means whereby the Company may be able, by granting stock options and shares of restricted stock, to attract, retain and motivate capable and loyal employees, non-employee directors, consultants and advisors of the company, for the benefit of the Company and its shareholders.

On November 1, 2007, the board of directors granted options to purchase 560,000 shares of the Company's common stock under the Company's 2006 Incentive Stock Option Plan. The Company granted options to purchase 500,000 shares of the Company's common stock, to members of the board and options to purchase 60,000 shares of the Company's common stock to one employee pursuant to an employment agreement. These options were granted at a price of $5.18 per share and the optionees were fully vested on the grant date. As of June 30, 2011, options to purchase a total of 265,963 shares remain outstanding but unexercised. The board of directors determined that no future grants will be made pursuant to the 2006 Incentive Stock Option Plan. All future stock compensation will be issued under the 2009 Equity Incentive Plan.

The Company accounts for stock-based compensation under the provisions of FASB ASC 718-10-55. This standard requires the Company to record an expense associated with the fair value of stock-based compensation. The Company uses the Black-Scholes option valuation model to calculate stock-based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. The Company used the simplified method to determine the expected term of the options due to the lack of sufficient historical data. Changes in these assumptions can materially affect the fair value estimate. The total fair value of the options is recognized as compensation over the vesting period. There have been no stock options granted in the six months ended June 30, 2011 under the 2006 Stock Option Plan or the 2009 Equity Incentive Plan.

The following summarizes activities concerning outstanding options to purchase shares of the Company’s common stock as of and for the period ending June 30, 2011:

- No options were exercised or forfeited in the six months ended June 30, 2011.
- No options expired during the six months ended June 30, 2011.
- Options covering 265,963 shares are exercisable and outstanding at June 30, 2011.
- There is no further compensation expense that will be recognized in future periods relative to any options that had been granted as of June 30, 2011, because the Company recognized the entire fair value of such compensation upon vesting of the options.
- There were no unvested options at June 30, 2011.

Warrants Granted February 2009

On February 27, 2009, in conjunction with the closing of the revolving credit facility (see Note 8), the Company issued CIT warrants to purchase a total of 300,000 shares of common stock exercisable at $5.00 per share. The total fair value of the warrants was calculated using the Black-Scholes valuation model based on factors present at the time the warrants were issued. The fair value of the warrants is included in Debt Issuance Costs and is being amortized over the term of the facility. CIT exercised the warrants in January 2011.

Restricted Stock Awards

During the six months ended June 30, 2011, the Company issued 590,735 restricted shares of common stock as compensation to officers and employees of the Company, the majority of which were issued under the long term equity incentive plan. The restricted shares vest over various terms with all restricted shares vesting no later than January 1, 2014. As of June 30, 2011, there was approximately $22.2 million of total unrecognized compensation expense related to unvested restricted stock. This compensation expense will be recognized over the remaining vesting period of the grants. The Company has assumed a zero percent forfeiture rate for restricted stock.

The following table reflects the outstanding restricted stock awards and activity related thereto for the six months ended June 30, 2011:

	Six Months Ended June 30, 2011	
	Number of Shares	Weighted-Average Price
Restricted Stock Awards:		
Restricted Shares Outstanding at the Beginning of Period	1,135,622	$ 13.28
Shares Granted	590,735	$ 27.96
Lapse of Restrictions	(312,459)	$ 15.26
Restricted Shares Outstanding at June 30, 2011	1,413,898	$ 18.97

NOTE 8 REVOLVING CREDIT FACILITY

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

On May 26, 2010, the Company completed the assignment of its revolving credit facility to Macquarie from CIT. In connection with the assignment the Company and Macquarie entered into an Amended and Restated Credit Agreement governing the facility (the "Credit Facility").

The Credit Facility provides up to a maximum principal amount of $100 million of working capital for exploration and production operations. The borrowing base of funds available under the Credit Facility is re-determined semi-annually based upon the net present value, discounted at 10% per annum, of the future net revenues expected to accrue from its interests in proved reserves estimated to be produced from its crude oil and natural gas properties. Macquarie waived the requirement that the Company redetermine its borrowing base upon receipt of its December 31, 2010 reserve report because the Company did not have any outstanding borrowings under the Credit Facility. $25 million of financing was currently available under the Credit Facility as of June 30, 2011. The Credit Facility terminates on May 26, 2014. The Company had no borrowings under the Credit Facility at June 30, 2011 and December 31, 2010.

The Company has the option to designate the reference rate of interest for each specific borrowing under the Credit Facility as amounts are advanced. Borrowings based upon the London interbank offering rate ("LIBOR") will bear interest at a rate equal LIBOR plus a spread ranging from 2.5% to 3.25% depending on the percentage of borrowings base that is currently advanced. Any borrowings not designated as being based upon LIBOR will bear interest at a rate equal to the greater of (a) the current prime rate published by the Wall Street Journal, or (b) the current one month LIBOR rate plus 1.0%, plus in either case a spread ranging from 2% to 2.5%, depending on the percentage of borrowing base that is currently advanced. The Company has the option to designate either pricing mechanism. Payments are due under the Credit Facility in arrears, in the case of a loan based on LIBOR on the last day of the specified interest period and in the case of all other loans on the last day of each March, June, September and December. All outstanding principal is due and payable upon termination of the Credit Facility.

The 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 Amended and Restated Credit Agreement, failure to observe or perform certain covenants, conditions or agreements under the Amended and Restated Credit Agreement, a change in control of the Company, default under any other material indebtedness the Company might have, bankruptcy and similar proceedings and failure to pay disbursements from lines of credit issued under the Credit Facility. The Company was not in default on the Credit Facility as of June 30, 2011.

The Credit Facility requires that the Company enter into swap agreements with Macquarie for each month of the thirty-six (36) month period following the date on which each such swap agreement is executed, the notional volumes for which when aggregated with other commodity swap agreements and additional fixed-price physical off-take contracts then in effect, as of the date such swap agreement is executed, is not less than 50%, nor exceeds 90%, of the reasonably anticipated projected production from the Company's proved developed producing reserves, as defined at the time of the agreement. The Company entered into swap agreements as required at the time, and presently there are no material hedging requirements imposed by Macquarie.

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

See Note 16 below regarding an amendment and restatement of the Credit Facility that occurred subsequent to June 30, 2011.

NOTE 9 ASSET RETIREMENT OBLIGATION

The Company has asset retirement obligations associated with the future plugging and abandonment of proved properties and related facilities. Under the provisions of FASB ASC 410-20-25, the fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

The following table summarizes the Company's asset retirement obligation transactions recorded in accordance with the provisions of FASB ASC 410-20-25 during the six months ended June 30, 2011:

	Six Months Ended June 30, 2011
Beginning Asset Retirement Obligation	$ 459,326
Liabilities Incurred for New Wells Placed in Production	199,996
Accretion of Discount on Asset Retirement Obligations	12,524
Ending Asset Retirement Obligation	$ 671,846

NOTE 10 INCOME TAXES

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

The income tax provision for the six months ended June 30, 2011 and 2010 consists of the following:

	Six Months Ended June 30,	
	2011	2010
Current Income Taxes	$2,300	$-
Deferred Income Taxes		
Federal	7,015,000	3,915,000
State	1,535,000	695,000
Total Provision	$8,552,300	$4,810,000

Under FASB ASC 740-10-05-6, tax benefits are recognized only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely to be realized upon ultimate settlement. Unrecognized tax benefits are tax benefits claimed in the Company's tax returns that do not meet these recognition and measurement standards.

The Company has no liabilities for unrecognized tax benefits.

The Company's policy is to recognize potential interest and penalties accrued related to unrecognized tax benefits within income tax expense. For the six months ended June 30, 2011, the Company did not recognize any interest or penalties in its condensed statement of operations, nor did it have any interest or penalties accrued in its condensed balance sheet at June 30, 2011 relating to unrecognized benefits.

The tax years 2010, 2009, 2008 and 2007 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which the Company is subject.

NOTE 11 FAIR VALUE

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

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

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

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

The following schedule summarizes the valuation of financial instruments measured at fair value on a recurring basis in the balance sheet as of June 30, 2011 and December 31, 2010.

	Far Value Measurements at June 30, 2011 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives - Current Liability	$-	$(14,279,978)	$ -
Commodity Derivatives - Non-Current Liability	$-	$(1,764,445)	$ -
Total	$-	$(16,044,423)	$ -

	Fair Value Measurements at December 31, 2010 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives - Current Liability	$-	$(11,145,318)	$ -
Commodity Derivatives - Non-Current Liability	$-	$(5,022,657)	$ -
Short-Term Investments (See Note 3)	$39,726,700	$-	$ -
Total	$39,726,700	$(16,167,975)	$ -

There were no transfers of financial assets or liabilities between Level 1 and Level 2 inputs for the six month period ended June 30, 2011.

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

Level 2 liabilities consist of derivative liabilities (see Note 13). Under FASB ASC 820-10-55, the fair value of the Company's derivative financial instruments is determined based on spot prices and the notional quantities. The fair value of all derivative contracts is reflected on the condensed balance sheet. The current derivative liability amounts represent the fair values expected to be settled in the subsequent year.

NOTE 12 FINANCIAL INSTRUMENTS

The Company’s non-derivative financial instruments include cash and cash equivalents, accounts receivable, short term investments, and accounts payable. The carrying amount of cash and cash equivalents, accounts receivable, accounts payable, and line of credit approximate fair value because of their immediate or short-term maturities.

The Company’s accounts receivable relate to crude oil and natural gas sold to various industry companies. Credit terms, typical of industry standards, are of a short-term nature and the Company does not require collateral. Management believes the Company's accounts receivable at June 30, 2011 and December 31, 2010 do not represent significant credit risks as they are dispersed across many counterparties. The Company has determined that no allowance for doubtful accounts is necessary at June 30, 2011 and December 31, 2010.

NOTE 13 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

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

Crude Oil Derivative Contracts Cash-flow Hedges

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

On November 1, 2009, due to the volatility of price differentials in the Williston Basin, the Company de-designated all derivates that were previously classified as cash flow hedges and, in addition, the Company has elected not to designate any subsequent derivative contracts as cash flow hedges under FASB ASC 815-20-25. Beginning on November 1, 2009, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses are recorded to Gain (Loss) on Settled Derivatives and unrealized gains or losses are recorded to Mark-to-Market of Derivative Instruments on the Condensed Statement of Operations rather than as a component of other comprehensive income (loss) or other income (expense).

Derivative instruments are presented on a gross basis, even when those instruments are subject to a master netting arrangement and qualify for net presentations on the balance sheet. The Company has a master netting agreement on each of the individual crude oil contracts and therefore the current asset and liability are netted on the condensed balance sheet and the non-current asset and liability are netted on the condensed balance sheet.

The net mark-to-market loss on the Company's remaining swaps that qualified for cash flow hedge accounting at the date the decision was made to discontinue hedge accounting totals $705,135 and $1,259,085 as of June 30, 2011 and December 31, 2010, respectively. The Company has recorded that amount as accumulated other comprehensive income in stockholders' equity and the entire amount will be amortized into revenues as the original forecasted hedged crude oil production occurs in the following periods.

For the Quarter Ended	Commodity Derivatives
September 30, 2011	$ 295,950
December 31, 2011	307,875
March 31, 2012	101,310
Total	$ 705,135

Crude-Oil Derivative Contracts Cash-flow Not Designated as Hedges

The Company realized a loss on settled derivatives of $8,870,287 and $5,608,231 and a mark-to-market of derivative loss of $430,397 and a mark-to-market of derivative gain of $20,848,232 on derivative instruments for the six and three months ended June 30, 2011, respectively. The Company realized a gain on settled derivatives of $126,936 and $303,919 and a mark-to-market of derivatives gain of $3,260,383 and $4,251,199 on derivative instruments for the six and three months ended June 30, 2010, respectively.

The following table reflects open commodity swap contracts as of June 30, 2011, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Oil (Barrels)	Fixed Price	Weighted Avg NYMEX Reference Price
Oil Swaps			
07/01/11 – 02/29/12	15,000	51.25	97.19
07/01/11 – 12/31/11	9,000	66.15	96.86
07/01/11 – 12/31/11	24,000	82.60	96.88
07/01/11 – 12/31/11	9,000	84.25	96.88
07/01/11 – 12/31/11	27,498	80.90	96.88
07/01/11 – 12/31/11	46,000	88.00	96.87
07/01/11 – 06/30/12	170,502	80.00	98.85
07/01/11 – 06/30/12	398,000	81.50	98.13
07/01/11 – 06/30/12	132,000	85.50	97.89
01/01/12 12/31/12	376,000	95.15	100.32
01/01/12 12/31/12	240,000	100.00	100.04

As of June 30, 2011, the Company had a total volume on open commodity swaps of 1,447,000 barrels at a weighted average price of approximately $88.13.

The following table reflects the weighted average price of open commodity swap contracts as of June 30, 2011, by year with associated volumes.

Weighted Average Price
Of Open Commodity Swap Contracts

Year	Volumes (Bbl)	Weighted Average Price
2011	432,000	$81.67
2012	1,015,000	90.87

In addition to the open commodity swap contracts the Company has entered into a costless collar. The costless collars are used to establish floor and ceiling prices on anticipated crude oil and natural gas production. There were no premiums paid or received by the Company related to the costless collar agreement. The Company purchased put options at $85.00 per barrel and sold call options at $101.75 per barrel. At June 30, 2011 the Company has 243,000 barrels of crude oil collared between $85.00 and $101.75. The costless collar amounts settle between July 2011 and December 2011.

At June 30, 2011 and December 31, 2010, the Company had derivative financial instruments under FASB ASC 815-20-25 recorded on the balance sheet as set forth below:

Type of Contract	Balance Sheet Location	June 30, 2011 Estimated Fair Value	December 31, 2010 Estimated Fair Value
Derivative Assets:			
Oil Contracts	Other current assets	$ 450,971	$ -
Oil Contracts	Other non-current assets	-	-
Total Derivative Assets		$ 450,971	$ -
Derivative Liabilities:			
Oil Contracts	Other current liabilities	$ (14,730,949)	$ (11,145,318)
Oil Contracts	Other non-current liabilities	(1,764,445)	(5,022,657)
Total Derivative Liabilities		$ (16,495,394)	$ (16,167,975)

The following disclosures are applicable to the Company's financial statements, as of June 30, 2011 and December 31, 2010:

Derivative Type	Location of Loss for Effective and Ineffective Portion of Derivative In Income	Amount of Loss Reclassified from AOCI into Income — Three Months Ended June 30, 2011	2010	Six Months Ended June 30, 2011	2010
Commodity - Cash Flow	Loss on Settled Derivatives	$ 283,800	$ 273,950	$ 553,950	$ 503,050

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

NOTE 14 COMPREHENSIVE INCOME

The Company follows the provisions of FASB ASC 220-10-55 which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income includes all changes in equity during a period, except those resulting from investments and distributions to shareholders of the Company.

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

	Three Months Ended June 30, 2011	2010	Six Months Ended June 30, 2011	2010
Net Income	$ 20,432,900	$ 6,120,866	$ 13,375,058	$ 7,680,496
Unrealized gains on Marketable Securities (net of tax of $404,000 and $331,000 for the three months ended June 30, 2011 and 2010 and $109,000 and $459,000 for the six months ended June 30, 2011 and 2010)	630,761	529,516	173,846	725,981
Reclassification of derivative instruments included in income (net of tax of $111,000 and $106,000 for the three months ended June 30, 2011 and 2010 and $212,000 and $195,000 for the six months ended June 30, 2011 and 2010)	172,800	167,950	341,950	308,050
Comprehensive income net	$ 21,236,461	$ 6,818,332	$ 13,890,854	$ 8,714,527

NOTE 15 COMMITMENTS & CONTINGENCIES

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

NOTE 16 SUBSEQUENT EVENTS

On August 8, 2011, the Company and Macquarie Bank Limited ("Macquarie") entered into a Second Amended and Restated Credit Agreement (the "Restated Credit Agreement") governing the Company's revolving credit facility with Macquarie. The facility now provides that the aggregate maximum credit amount may be increased in the future to up to $500 million. The Restated Credit Agreement provides for an initial borrowing base of $150 million, subject to the aggregate maximum credit amount then in effect. Initially, the Restated Credit Agreement provides for an aggregate maximum credit amount of $25 million in principal amount of borrowings. Such aggregate maximum credit amount may be increased, subject to various conditions, in increments of $20 million, but in no event to more than $500 million. One of the conditions to any such increase would be an additional commitment of such funds by Macquarie or another lender. Financing available under the facility is equal to the lesser of the aggregate maximum credit amount and the borrowing base.

In connection with preparing the unaudited financial statements for the six months ended June 30, 2011, the Company has evaluated subsequent events for potential recognition and disclosure through the date of this filing and determined that there were no subsequent events, except for what has been disclosed above, which required recognition or disclosure in the financial statements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Cautionary Statement Concerning Forward-Looking Statements

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding future events and our future results that are subject to the safe harbors created under the Securities Act of 1933 (the "Securities Act") and the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this report regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, and indebtedness covenant compliance are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "anticipate," "target "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of f events or outcomes. Items contemplating or making assumptions about actual or potential future sales, market size, collaborations, and trends or operating results also constitute such forward-looking statements.

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

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results actually achieved may differ materially from expected results described in these statements. Forward-looking statements speak only as of the date they are made. You should consider carefully the statements in the section entitled "Item 1A. Risk Factors" and other sections of our Annual Report on Form 10-K for the fiscal year ended December 31, 2010, as updated by subsequent reports we file with the SEC, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

Overview and Outlook

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

We are focused on maintaining a low cash 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. We accelerated our acreage acquisition activities throughout the Williston Basin in the first and second quarters of 2011 and continue to monitor numerous additional potential acquisitions.

We control approximately 155,353 net acres in the Williston Basin targeting the Bakken and Three Forks formations. We continue to expand our position through aggressive acquisition and leasing programs. We have no material lease expirations until the first half of 2012, and continue to expand our position through aggressive acquisition and leasing programs.

During the three months ended June 30, 2011, we continued the development of our oil and gas properties primarily in the Williston Basin Bakken play. During the second quarter of 2011, we spud approximately 7.2 net wells and added production from approximately 73 gross (6.7 net) wells. During the first half of 2011, we spud approximately 17 net wells and added production from approximately 128 gross (11.7 net) wells. As of June 30, 2011, we owned working interests in 439 successful discoveries, consisting of 433 targeting the Bakken/Three Forks formation, one targeting the Mission Canyon formation, and five targeting the Red River formation. As of June 30, 2011, we were participating in the drilling or completion of 161 gross (15.02 net) Bakken or Three Forks wells drilling, awaiting completion or completing. Our average daily production in the second quarter of 2011 was approximately 4,400 BOE per day ("BOEPD"). June 2011 daily production averaged approximately 5,200 BOEPD.

We believe recent discoveries in Roosevelt and Richland Counties of Montana and in Billings, Stark, and McKenzie Counties of North Dakota have substantially expanded the delineated area of high quality Bakken and Three Forks production. The rapid accelerating pace of drilling has dramatically changed the dynamics of this oil play. Acreage acquisition represents our core competency and we expect to continue to leverage our leasing expertise as the Bakken and Three Forks plays continue to increase in size and scope.

As of August 9, 2011, Northern Oil had 46,351 net acres either held by production or under the bit, which represents approximately 30% of Northern Oil’s total Bakken and Three Forks acreage position at June 30, 2011. Northern Oil expects that approximately 50% of its current acreage will be held by production or under the bit by the end of 2011.

Our capital expenditures relating to drilling activities approximated $105 million for the six months ending June 30, 2011 and are expected to approximate $260 million for the entire 2011 year based on wells currently drilling and expected to spud by 2011 year-end. We currently expect average well costs to approximate $6.5 million per well, which represents an increase from $6.3 million per well at the end of 2010.

Acquisition Activity

During the second quarter of 2011, we acquired leasehold interests covering an aggregate of 12,767 net acres for an average of $1,995 per net acre for an aggregate of $25.5 million. Of the acquired net acres in the second quarter, approximately fifty six percent was permitted, or spaced for permit at the end of the second quarter of 2011. For the six months ended June 30, 2011, we have acquired approximately 24,281 net acres at an aggregate price of approximately $43.9 million,or an average price of $1,808 per net acre.

Completion Activity

During the second quarter of 2011, we continued to experience delays in fracture stimulation appointments for wells across all operators with whom we participate. We believe this trend has been driven primarily by wet weather delays impacting the timing for the gathering of oil and gas, and increases in the inventory of wells awaiting fracture stimulation throughout the Williston Basin. Additionally, constraints in moving fracture stimulation supplies, such as frac sand, into the field have delayed well completions on occasion in the past. We expect that for the next quarter, delay between fracture stimulation and completion may continue to average as much as six to nine weeks pending any one operator that we are a working interest partner with. We do not expect that this will affect the pace of drilling and we continue to see wells drilled to total depth at an accelerated pace. However, delays in fracture stimulation have the effect of delaying production additions.

Divestiture Activity

In January 2010, our board of directors approved an arrangement whereby we efficiently divest minimal working interests in wells. In March 2010, we entered into an agreement with a private unrelated company, whereby we have the option (but not the obligation) to sell minimal wellbore interests in any drilling unit where our interest constitutes less than 0.0050 working interest in a well. We retain the underlying leasehold interest and only assign the wellbore interest. Through this arrangement, we have divested wellbores with an average working interest of approximately 0.0025 of one net well for a total aggregate divestiture of 0.23 of one net well. We believe the divestiture of these minimal working interests creates value by avoiding the administrative, reserve engineering and accounting costs that would be associated with these minimal interests. The proceeds from sales under the agreement were applied to reduce the capitalized costs of oil and gas properties.

In November 2009, we agreed to participate in the exploration and development of Slawson's Anvil project in Roosevelt and Sheridan Counties, Montana and Williams County, North Dakota. In April 2011, we sold our interest in the Anvil project for $4,960,784 along with Slawson, who also desired to sell its entire interest in the project. As of the date of sale, our cost basis in the Anvil project was $1,785,007. Slawson had drilled and completed one well in the project area prior to the divestiture –the Mayhem #1-19H well – and we retained our interest in that wellbore in connection with the divestiture. The proceeds from the sale under the agreement was applied to reduce the capitalized costs of oil and gas properties.

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

2011 Drilling Activity

We are participating in numerous drilling activities on properties presently owned and intend to drill or develop other properties acquired in the future. We completed and commenced production in an additional 73 gross (approximately 6.7 net) wells during the quarter. We intend to continue development efforts on our existing acreage in North Dakota and Montana. As of June 30, 2011 we expect to spud approximately 40 net wells by the end of 2011. The expected wells is based upon permitted activity and the increasing rig count. During the second quarter of 2011, according to the State of North Dakota Industrial Commission, the state had an average rig count of 173 rigs.

As of June 30, 2011, we had a working interest in a total of 600 gross (52.71 net) wells that were either drilling, awaiting completion, completing or producing, consisting of 439 gross producing (37.69 net) wells and 161 gross drilling, awaiting completion or completing (15.02 net) wells. As of August 9, 2011, we had a working interest in 166 gross (17.14 net) wells that were either drilling, awaiting completion or completing. Permits continue to be issued for spacing units in which we have undeveloped acreage interests within North Dakota and Montana.

Production History

The following table presents information about our produced crude oil and natural gas volumes during the three month and six month periods ended June 30, 2011, compared to the three month and six month periods ended June 30, 2010. As of June 30, 2011, we were selling crude oil and natural gas from a total of 439 gross (37.6 net) wells, compared to 202 gross (14.36 net) wells at June 30, 2010. All data presented below is derived from accrued revenue and production volumes for the relevant period indicated.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	% Change	2010	2011	% Change	2010
Net Production:						
Oil (Bbl)	376,170	126 %	166,341	711,411	149 %	285,955
Natural Gas (Mcf)	148,547	292 %	37,931	276,833	292 %	70,534
Barrel of Oil Equivalent (Boe)	400,928	132 %	172,663	757,550	154 %	297,711
Average Sales Prices:						
Oil (per Bbl)	95.69	38 %	69.15	90.10	29 %	69.58
Effect of settled oil hedges on average price (per Bbl)	(14.91)	(915 %)	1.83	(12.47)	(2934 %)	0.44
Oil net of settled hedging (per Bbl)	80.78	14 %	70.98	77.63	11 %	70.02
Natural Gas and Other Liquids (per Mcf)	5.35	6 %	5.07	5.42	19 %	4.56
Effect of natural gas hedges on average price (per Mcf)	-	-	-	-	-	-
Natural gas net of hedging (per Mcf)	5.35	6 %	5.07	5.42	19 %	4.56
Average Production Costs:						
Oil (per Bbl)	6.19	84 %	3.37	5.84	76 %	3.32
Natural Gas (per Mcf)	0.38	41 %	0.27	0.35	52 %	0.23
Barrel of Oil Equivalent (Boe)	5.94	80 %	3.30	5.61	73 %	3.25

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 for the three month and six month periods ended June 30, 2011 compared to the three month and six month periods ended June 30, 2010.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Depletion of oil and natural gas properties	$8,349,600	$2,600,836	$15,213,079	$4,484,441

Productive Oil Wells

The following table summarizes gross and net productive oil wells by state at June 30, 2011 and June 30, 2010. 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 table also does not include wells which were awaiting completion, in the process of completion or awaiting flow back subsequent to fracture stimulation.

	June 30,			
	2011		2010	
	Gross	Net	Gross	Net
North Dakota	424	34.74	194	12.98
Montana	15	2.95	8	1.38
Total:	439	37.69	202	14.36

Results of Operations for the periods ended June 30, 2010 and June 30, 2011.

Our business activities are focused primarily on developing our current acreage position and identifying potential strategic acreage and production acquisitions to continue to consistently increase production and revenues.

During the six months ended June 30, 2011, we continued the development of our oil and gas properties primarily in the Williston Basin Bakken play. Our wells were drilled with a 100% success rate in the three months ended June 30, 2011. As of June 30, 2011, we had established production from 439 total gross wells in which we hold working interests, compared to 202 as of June 30, 2010. Since inception we have completed 368 gross (30.42 net) Bakken wells, 65 gross (6.09 net) Three Forks wells, and six gross (1.18 net) Mission Canyon and Red River wells as of June 30, 2011.

We recognized $35,481,664 in revenues from sales of crude oil and natural gas for the three months ended June 30, 2011, compared to $11,664,873 for the three months ended June 30, 2010. We recognized $62,523,285 in revenues from sales of crude oil and natural gas for the six months ended June 30, 2011, compared to $20,033,720 for the six months ended June 30, 2010. These increases in revenue from sales of crude oil and natural gas are primarily due to our continued addition of wells and an increase in our average realized crude oil prices period-over-period. We have added wells each quarter since the first quarter of 2008 and, in particular, added production from 6.7 additional net wells during the second quarter of 2011. During the three months ended June 30, 2011, we realized a $80.78 average price per barrel of crude oil (after the effect of settled hedges), compared to a $70.98 average price per barrel of crude oil (after the effect of settled hedges) during the three months ended June 30, 2010. During the six months ended June 30, 2011, we realized a $77.63 average price per barrel of crude oil before the effect of settled hedges, compared to a $70.02 average price per barrel of crude oil before the effect of settled hedges during the six months ended June 30, 2010.

We realized net income of $20,432,900 (representing approximately $0.33 per diluted share) for the three months ended June 30, 2011 and net income of $6,120,866 (representing approximately $0.12 per diluted share) for the three months ended June 30, 2010. We realized net income of $13,375,058 (representing approximately $0.22 per diluted share) for the six months ended June 30, 2011 and net income of $7,680,496 (representing approximately $0.16 per diluted share) for the six months ended June 30, 2010. These increases in income are primarily due to our continued addition of wells and an increase in our average realized crude oil prices period-over-period, partially offset by settled hedging losses.

Total operating expenses were $17,103,690 for the three months ended June 30, 2011, compared to total operating expenses of $6,133,565 for the three months ended June 30, 2010. Total operating expenses were $31,963,021 for the six months ended June 30, 2011, compared to total operating expenses of $10,730,501 for the six months ended June 30, 2010. These increases in operating expenses are due primarily to increased depletion of oil and gas properties, production expenses, production taxes and general and administrative expenses associated with our continued addition of crude oil and natural gas production from new wells.

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During the three months ended June 30, 2011, we had production expenses of $2,615,546 compared to production expenses of $561,427 during the three months ended June 30, 2010. During the six months ended June 30, 2011, we had production expenses of $4,631,902 compared to production expenses of $893,757 during the six months ended June 30, 2010. These increases in production expense are primarily due to the continued addition of producing oil and gas properties, exposure to new operators and new development areas, an increase in working interests, mature wells utilizing artificial lift and the general aging of our production.

During the three months ended June 30, 2011, we incurred production taxes of $3,311,037, compared to production taxes of $1,024,277 during the three months ended June 30, 2010. During the six months ended June 30, 2011, we incurred production taxes of $5,926,901, compared to production taxes of $1,670,143 during the six months ended June 30, 2010. The increase in production taxes is primarily due to the continued addition of producing oil and gas properties and related sales.

We recorded depletion of $8,349,600 during the three months ended June 30, 2011, compared to depletion of $2,600,836 during the three months ended June 30, 2010. We recorded depletion of $15,213,079 during the six months ended June 30, 2011, compared to depletion of $4,484,441 during the six months ended June 30, 2010. These increases in depletion are primarily due to the addition of proven properties subject to the depletion calculation as well as the continued addition of producing oil and gas properties. Depletion expense for the three months ended June 30, 2011, was $20.83 per BOE, compared to $15.06 per BOE, for the three months ended June 30, 2010. Depletion expense for the six months ended June 30, 2011, was $20.08 per BOE, compared to $15.06 per BOE, for the six months ended June 30, 2010. These increases in depletion per BOE are primarily attributed to the increase in acreage and well development costs relative to the increase in our proved reserves.

We had general and administrative expenses of $2,749,418 and $1,911,543 during the three months ended June 30, 2011 and 2010, which included $1,244,244 and $718,471 net of share based compensation expense, respectively. We had general and administrative expenses of $6,040,007 and $3,618,511 during the six months ended June 30, 2011 and 2010, which included $2,676,662 and $1,612,142 net of share based compensation expense, respectively. The increases in general and administrative expenses are primarily due to the increase in share based compensation, headcount, and professional service fees.

Use of Non-GAAP Financial Measures

Our non-GAAP net income for the three months ended June 30, 2011, which excludes unrealized mark-to-market hedging gains and losses net of tax, was $7,715,668 (representing approximately $0.12 per diluted share) as compared to $3,502,667 (representing approximately $0.07 per diluted share) in the quarter ended June 30, 2010. Our non-GAAP net income for the six months ended June 30, 2011, which excludes unrealized mark-to-market hedging gains and losses net of tax, was $13,637,455 (representing approximately $0.22 per diluted share) as compared to $5,692,113 (representing approximately $0.12 per diluted share) in the six months ended June 30, 2010. These increases in non-GAAP net income are primarily due to our continued addition of crude oil and natural gas production from new wells and higher realized commodity prices period over period.

We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion and amortization, (iv) accretion of abandonment liability, (v) pre-tax unrealized gain and losses on commodity risk and (vii) non-cash expenses relating to share based payments recognized under ASC Topic 718. Adjusted EBITDA for the three months ended June 30, 2011 was $22,700,077 (representing approximately $0.37 per diluted share), compared to Adjusted EBITDA of $9,677,386 (representing approximately $0.19 per diluted share) for the second quarter of 2010. Adjusted EBITDA for the six months ended June 30, 2011 was $41,328,499 (representing approximately $0.67 per diluted share), compared to Adjusted EBITDA of $16,095,094 (representing approximately $0.34 per diluted share) for the six months ended June 30, 2010. These increases in Adjusted EBITDA are primarily due to our continued addition of crude oil and natural gas production from new wells and higher realized commodity prices period over period.

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

The non-GAAP financial information is presented using consistent methodology from quarter-to-quarter. These measures should be considered in addition to results prepared in accordance with GAAP. In addition, these non-GAAP financial measures are not based on any comprehensive set of accounting rules or principles. We believe that non-GAAP financial measures have limitations in that they do not reflect all of the amounts associated with our results of operations as determined in accordance with GAAP and that these measures should only be used to evaluate our results of operations in conjunction with the corresponding GAAP financial measures.
Net income excluding unrealized mark-to-market hedging gains (losses) and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to GAAP is included below:

USE OF NON GAAP FINANCIAL MEASURES

Northern Oil and Gas, Inc.
Reconciliation of Adjusted EBITDA

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Net Income	$20,432,900	$6,120,866	$13,375,058	$7,680,496
Add Back:				
Income Tax Provision	13,060,000	3,833,000	8,552,300	4,810,000
Depreciation, Depletion, Amortization, and Accretion	8,427,689	2,766,688	15,364,211	4,548,090
Share Based Compensation	1,505,174	1,193,072	3,363,345	2,006,369
Mark-to-Market of Derivative Instruments	(20,848,232)	(4,251,199)	430,397	(3,260,383)
Interest Expense	122,546	14,959	243,188	310,522
Adjusted EBITDA	$22,700,077	$9,677,386	$41,328,499	$16,095,094
Adjusted EBITDA Per Common Share - Basic	$0.37	$0.19	$0.67	$0.34
Adjusted EBITDA Per Common Share - Diluted	$0.37	$0.19	$0.67	$0.34
Weighted Average Shares Outstanding – Basic	61,686,463	49,934,409	61,586,603	47,032,602
Weighted Average Shares Outstanding - Diluted	62,053,888	50,609,944	62,028,292	47,593,962

Northern Oil and Gas, Inc.
Reconciliation of Adjusted EBITDA Per Common Share - Basic

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Net Income Per Common Share - Basic (As Reported)	$0.33	$0.12	$0.22	$0.16
Add Back:				
Income Tax Provision	0.22	0.08	0.14	0.10
Depreciation, Depletion, Amortization, and Accretion	0.14	0.06	0.25	0.10
Share Based Compensation	0.02	0.02	0.05	0.04
Mark-to-Market of Derivative Instruments	(0.34)	(0.09)	0.01	(0.07)
Interest Expense	0.00	0.00	0.00	0.01
Adjusted EBITDA Per Common Share - Basic (Adjusted for Non-GAAP Measurements)	$0.37	$0.19	$0.67	$0.34

Northern Oil and Gas, Inc.
Reconciliation of Adjusted EBITDA Per Common Share - Diluted

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Net Income Per Common Share - Diluted (As Reported)	$0.33	$0.12	$0.22	$0.16
Add Back:				
Income Tax Provision	0.22	0.08	0.14	0.10
Depreciation, Depletion, Amortization, and Accretion	0.14	0.05	0.25	0.10
Share Based Compensation	0.02	0.02	0.05	0.04
Mark-to-Market of Derivative Instruments	(0.34)	(0.08)	0.01	(0.07)
Interest Expense	0.00	0.00	0.00	0.01
Adjusted EBITDA Per Common Share - Diluted	$0.37	$0.19	$0.67	$0.34

(Adjusted for Non-GAAP Measurements)

Northern Oil and Gas, Inc.
Reconciliation of GAAP Net Income to Non-GAAP Net Income Excluding
Unrealized Mark-to-Market Hedging Gains and Losses

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Net Income	$20,432,900	$6,120,866	$13,375,058	$7,680,496
Mark-to-Market of Derivative Instruments	(20,848,232)	(4,251,199)	430,397	(3,260,383)
Tax Impact	8,131,000	1,633,000	(168,000)	1,272,000
Net Income without Effect of Certain Items	$7,715,668	$3,502,667	$13,637,455	$5,692,113
Net Income Per Common Share - Basic	$0.13	$0.07	$0.22	$0.12
Net Income Per Common Share - Diluted	$0.12	$0.07	$0.22	$0.12
Weighted Average Shares Outstanding – Basic	61,686,463	49,934,409	61,586,603	47,032,602
Weighted Average Shares Outstanding - Diluted	62,053,888	50,609,944	62,028,292	47,593,962
Net Income Per Common Share - Basic	$0.33	$0.12	$0.22	$0.16
Change due to Mark-to-Market of Derivative Investments	(0.34)	(0.08)	0.01	(0.07)
Change due to Tax Impact	0.14	0.03	(0.01)	0.03
Net Income without Effect of Certain Items Per Common Share - Basic	$0.13	$0.07	$0.22	$0.12
Net Income Per Common Share - Diluted (As Reported)	$0.33	$0.12	$0.22	$0.16
Change due to Mark-to-Market of Derivative Investments	(0.34)	(0.08)	0.01	(0.07)
Change due to Tax Impact	0.13	0.03	(0.01)	0.03
Net Income without Effect of Certain Items Per Common Share - Diluted	$0.12	$0.07	$0.22	$0.12

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Liquidity and Capital Resources

We have historically met our capital requirements through the issuance of common stock and by borrowings. In the future, we anticipate we will be able to provide the necessary liquidity by the revenues generated from the sales of our crude oil and natural gas reserves in our existing properties, credit facility borrowings and potential equity issuances. However there is no guarantee the capital markets will be available to us on favorable terms or at all.

The following table summarizes total current assets, total current liabilities and working capital at June 30, 2011.

Current Assets	$135,653,959
Current Liabilities	$72,155,369
Working Capital	$63,498,590

Assignment of CIT Capital USA, Inc. Credit Facility to Macquarie Bank Limited

On May 26, 2010, we completed the closing of the assignment of our revolving credit facility to Macquarie Bank Limited ("Macquarie") from CIT Capital USA Inc., and entered into an amended credit agreement in connection with such assignment.

The facility with Macquarie provides us with an initial borrowing base of $25 million and maximum borrowings of up to $100 million (the "Credit Facility"). The Credit Facility may be used to provide working capital for exploration and production operations. The Credit Facility has a four year term and does not contain any minimum interest rate on borrowings. Borrowings, if any, will bear interest at a spread ranging from 2.5% to 3.25% over the London Interbank Offered Rate (LIBOR) or prime rate, as the case may be, based upon the percentage of borrowing base that is advanced at any given time.

As of June 30, 2011, we had no borrowings outstanding under the Credit Facility.

All of our obligations under the Credit Facility and the swap agreements with Macquarie (as discussed in Item 3) continue to be secured by a first priority security interest in any and all of our assets pursuant to the terms of an Amended and Restated Guaranty and Collateral Agreement and perfected by an amended and restated mortgage, notice of pledge and security and similar documents.

On August 8, 2011, we entered into a second amended and restated credit agreement (the "Restated Credit Agreement") governing the Credit Facility with Macquarie. The facility now provides that the aggregate maximum credit amount may be increased in the future to up to $500 million. The Restated Credit Agreement provides for an initial borrowing base of $150 million, subject to the aggregate maximum credit amount then in effect. Initially, the Restated Credit Agreement provides for an aggregate maximum credit amount of $25 million in principal amount of borrowings. Such aggregate maximum credit amount may be increased, subject to various conditions, in increments of $20 million, but in no event to more than $500 million. One of the conditions to any such increase would be an additional commitment of such funds by Macquarie or another lender. Financing available under the facility is equal to the lesser of the aggregate maximum credit amount and the borrowing base.

Satisfaction of Our Cash Obligations for the Next 12 Months

With the addition of equity capital during 2009 and 2010, our credit facility and our cash flows from operations, we believe we have sufficient capital to meet our drilling commitments and expected general and administrative expenses for the next twelve months at a minimum. Nonetheless, any strategic acquisition of assets or increase in drilling activity may require us to seek additional capital. We may also choose to seek additional capital rather than utilize our Credit Facility or other debt instruments to fund accelerated or continued drilling at the discretion of management and depending on prevailing market conditions. We will evaluate any potential opportunities for acquisitions as they arise. 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 acquisitions and drilling activities. Consequently, we may seek additional capital in the future to fund growth and expansion through additional equity or debt financing or credit facilities. No assurance can be made that such financing would be available, and if available it may take either the form of debt or equity. In either case, the financing could have a negative impact on our financial condition and our stockholders.

Though we were profitable in 2010 and the six months ended June 30, 2011, our prospects must be considered in light of the risks, expenses and difficulties frequently encountered by companies in their early stage of operations, particularly companies in the crude oil and natural gas exploration industry. Such risks include, but are not limited to, an evolving and unpredictable business model and the management of our growth. To address these risks we must, among other things, implement and successfully execute our business strategy, continue to develop and upgrade our technology, respond to competitive developments and attract, retain and motivate qualified personnel. There can be no assurance that we will be successful in addressing such risks, and the failure to do so can have a material effect on our business prospects, financial condition and results of operations.

Contractual Obligations and Commitments

Our material long-term debt obligations, capital lease obligations and operating lease obligations or purchase obligations are included in Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2010, and have not materially changed since that report was filed.

Critical Accounting Policies

Our critical accounting policies involving significant estimates include impairment testing of natural gas and crude oil production properties, asset retirement obligations, revenue recognition, derivative instruments and hedging activity, and income taxes. There were no material changes in our critical accounting policies involving significant estimates from those reported in our 2010 Annual Report on Form 10-K.

A description of our critical accounting policies was provided in Note 2 to the Financial Statements provided in Part II, Item 8 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2010 and, except as set forth below, have not materially changed since that report was filed.

Commodity Price Risk

The price we receive for our crude oil and natural gas production materially influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for crude oil and natural gas have been volatile, and our management believes these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue during 2010 and the first and second quarter of 2011 generally would have increased or decreased along with any increases or decreases in crude oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling crude oil that also increase and decrease along with crude oil prices.

We have previously entered into derivative contracts to achieve a more predictable cash flow by reducing our exposure to crude oil and natural gas price volatility. On November 1, 2009, due to the volatility of price differentials in the Williston Basin, we de-designated all derivatives that were previously classified as cash flow hedges and in addition, we have elected not to designate any subsequent derivative contracts as accounting hedges. As such, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains or losses on derivatives are recorded in Gain (Loss) on Settled Derivatives and unrealized gains or losses are recorded in Mark-to-Market of Derivative Instruments on the Statement of Operations rather than as a component of other comprehensive income (loss) or other Income (expense).

The following table reflects the weighted average price of open commodity swap contracts as of June 30, 2011, by year with associated volumes

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Weighted Average Price
Of Open Commodity Swap Contracts

Year	Volumes (Bbl)	Weighted Average Price
2011	432,000	$81.67
2012	1,015,000	$90.87

As of June 30, 2011, we had a total hedged volume on open commodity swaps of 1,447,000 barrels at a weighted average price of approximately $88.13.

In addition to the open commodity swap contracts we have entered into a costless collar. The costless collars are used to establish floor and ceiling prices on anticipated crude oil and natural gas production. There were no premiums paid or received by us related to the costless collar agreement. We purchased put options at $85.00 per barrel and sold call options at $101.75 per barrel. At June 30, 2011 we had 243,000 barrels of crude oil collared between $85.00 and $101.75. The costless collar amounts settle between April 2011 and December 2011.

Interest Rate Risk

We did not have outstanding any borrowings under our credit facilities or other obligations that would subject us to significant interest rate risk at June 30, 2011. Our Credit Facility would, however, subject us to interest rate risk on borrowings under that facility.

Our Credit Facility allows us to fix the interest rate of borrowings under it for all or a portion of the principal balance for a period up to six months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of our borrowings that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

As of June 30, 2011, our management, including our Chief Executive Officer and Chief Financial Officer, had evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) pursuant to Rule 13a-15(b) under the Exchange Act. Based upon and as of the date of the evaluation, our Chief Executive Officer and Chief Financial Officer concluded that information required to be disclosed is recorded, processed, summarized and reported within the specified periods and is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure of material information required to be included in our periodic SEC reports. Based on the foregoing, our management determined that our disclosure controls and procedures were effective as of June 30, 2011.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2011 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

On August 23, 2010, plaintiff Donald Rensch filed a three count shareholder derivative action in the United States District Court for the District of Minnesota against our company as nominal defendant, Michael L. Reger, Ryan R. Gilbertson, James R. Sankovitz and Chad D. Winter, James Randall Reger, James Russell Reger, Weldon W. Gilbertson, Douglas M. Polinsky, Joseph A. Geraci, II and Voyager Oil & Gas, Inc. ("Voyager"). The complaint alleges breach of fiduciary duty of loyalty and usurping of corporate opportunities by Messrs. M. Reger, Gilbertson, Sankovitz and Winter; asserts allegations against Messrs. James Randall Reger, Weldon W. Gilbertson, James Russell Reger, Douglas M. Polinsky and Joseph A. Geraci, II of aiding and abetting our officers in breaching their fiduciary duties and usurping of corporate opportunities in connection with the formation, capitalization, and operation of Plains Energy (Voyager's predecessor); and asserts a claim against Voyager for tortious interference with a prospective business relationship. The plaintiff seeks injunctive relief and damages, including imposing on Voyager and all of its assets a constructive trust for our company's benefit. We believe that each of the above claims lacks merit and intend to strongly defend our company and each of our current and/or former officers and directors in connection with this lawsuit. A motion to dismiss the lawsuit in the United States District Court for the District of Minnesota was filed on September 15, 2010. A hearing on the motion to dismiss was held on February 23, 2011. On the June 20, 2011, the motion to dismiss the lawsuit in the United States District Court for the District of Minnesota was granted, and the complaint was dismissed without prejudice. On July 20, 2011 plaintiff Donald Rensch filed an amended shareholder derivative action.

Our Company is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. Our company was a party to litigation claims arising in the ordinary course of business and seeking the quieting of title for a leasehold interest acquired from third parties. Our management believes that all litigation matters in which we are involved are not likely to have a material effect on our financial position, cash flows or results of operations.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the "Risk Factors" section of our Annual Report on Form 10-K for the year ended December 31, 2010, as updated by our subsequent filings on Form 10-Q (and otherwise) with the SEC.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

We did not issue any unregistered equity securities during the quarter ended June 30, 2011.

In May 2011, the Company's board of directors approved a stock repurchase program to acquire up to $150 million shares of the Company's outstanding common stock. The stock repurchase program will allow the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions. The Company has not made any repurchases under this program to date.

Item 6. Exhibits.

The exhibits listed in the accompanying exhibit index are filed as part of this Quarterly Report on Form 10-Q.

SIGNATURES

In accordance with the requirements of the Exchange Act, the Registrant has caused this Quarterly Report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHERN OIL AND GAS, INC.

Date:	August 9, 2011	By:	/s/ Michael L. Reger Michael L. Reger, Chief Executive Officer and Director
Date:	August 9, 2011	By:	/s/ Chad D. Winter Chad D. Winter, Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Exhibit Description	Method of Filing
3.1	Articles of Incorporation of Northern Oil and Gas, Inc. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on July 2, 2010.)	Incorporated by Reference
3.2	Bylaws of Northern Oil and Gas, Inc. (Incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed with the SEC on July 2, 2010.)	Incorporated by Reference
4.1	Form of Stock Certificate of Northern Oil and Gas, Inc. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on July 2, 2010.)	Incorporated by Reference
10.1*	Amended and Restated 2009 Equity Incentive Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement for the 2011 Annual Meeting of Shareholders filed ith the SEC on May 2, 2011.)	Incorporated by Reference
31.1	Certification 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 Electronically
31.2	Certification 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 Electronically
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed Electronically
101.INS	XBRL Instance Document(1)	Filed Electronically
101.SCH	XBRL Taxonomy Extension Schema Document(1)	Filed Electronically
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document(1)	Filed Electronically
101.LAB	XBRL Taxonomy Extension Label Linkbase Document(1)	Filed Electronically
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document(1)	Filed Electronically

* Management contract, compensatory plan or arrangement required to be filed as an exhibit to this Quarterly Report on Form 10-Q.

(1) The XBRL related information in Exhibit 101 to this Quarterly Report on Form 10-Q shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability of that section and shall not be incorporated by reference into any filing or other document pursuant to the Securities Act of 1933, as amended, except as shall be expressly set forth by specific reference in such filing or document.