NORTHERN OIL & GAS, INC.
Form 10-Q
November 05, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 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 September 30, 2015

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

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

As of October 31, 2015, there were 62,960,639 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." One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate or NGLs.

"Boe." A barrel of oil equivalent and is a standard convention used to express oil, NGL and natural gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or NGL.

"Boepd." Boe per day.

"Btu or British Thermal Unit." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"MBbl." One thousand barrels of crude oil, condensate or NGLs.

"MBoe." One thousand Boes.

"Mcf." One thousand cubic feet of natural gas.

"MMBbl." One million barrels of crude oil, condensate or NGLs.

"MMBoe." One million Boes.

"MMBtu." One million British Thermal Units.

"MMcf." One million cubic feet of natural gas.

"NGLs." Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

Terms used to describe our interests in wells and acreage:

"Basin." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"Completion." The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs, and/or natural gas.

"Conventional play." An area that is believed to be capable of producing crude oil, NGLs, and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

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

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

"Dry hole." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation." A layer of rock which has distinct characteristics that differs from nearby rock.

"Gross acres or Gross wells." The total acres or wells, as the case may be, in which a working interest is owned.

"Held by operations." A provision in an oil and gas lease that extends the stated term of the lease as long as drilling operations are ongoing on the property.

"Held by production." A provision in an oil and gas lease that extends the stated term of the lease as long as the property produces a minimum quantity of crude oil, NGLs, and natural gas.

"Hydraulic fracturing." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

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

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

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

"NYMEX." The New York Mercantile Exchange.

"OPEC." The Organization of Petroleum Exporting Countries.

"Productive well." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"Recompletion." The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“Reservoir.” A porous and permeable underground formation containing a natural accumulation of producible crude oil, NGLs and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

“Spacing.” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

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

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

“Unit.” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

“Wellbore.” The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

“West Texas Intermediate or WTI.” A light, sweet blend of oil produced from the fields in West Texas.

“Working interest.” The right granted to the lessee of a property to explore for and to produce and own crude oil, NGLs, natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Terms used to assign a present value to or to classify our reserves:

“Possible reserves.” The additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

“Pre-tax PV-10% or PV-10.” The estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

“Probable reserves.” The additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which together with proved reserves, are as likely as not to be recovered.

“Proved developed producing reserves (PDP’s).” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"Proved developed non-producing reserves (PDNP's)." Proved crude oil, NGLs, and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

"Proved reserves." The quantities of crude oil, NGLs and natural gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"Proved undeveloped drilling location." A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"Proved undeveloped reserves" or "PUDs." Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir or an analogous reservoir.

(i) The area of the reservoir considered as proved includes: (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil, NGLs or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

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

NORTHERN OIL AND GAS, INC.
FORM 10-Q

September 30, 2015

C O N T E N T S

PART I - FINANCIAL INFORMATION

Item 1. Condensed Financial Statements.

NORTHERN OIL AND GAS, INC.
CONDENSED BALANCE SHEETS
SEPTEMBER 30, 2015 AND DECEMBER 31, 2014

	September 30, 2015 (unaudited)	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 7,042,258	$ 9,337,512
Trade Receivables	91,293,591	85,931,719
Advances to Operators	2,002,713	930,034
Prepaid and Other Expenses	983,612	895,088
Derivative Instruments	87,881,527	128,893,220
Total Current Assets	189,203,701	225,987,573
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	2,308,144,736	2,167,452,297
Unproved	15,341,573	50,642,433
Other Property and Equipment	1,891,228	1,870,369
Total Property and Equipment	2,325,377,537	2,219,965,099
Less – Accumulated Depreciation, Depletion and Impairment	(1,568,202,406)	(458,038,546)
Total Property and Equipment, Net	757,175,131	1,761,926,553
DERIVATIVE INSTRUMENTS	6,330,398	25,013,011
DEFERRED TAX ASSET	31,695,562	-
DEBT ISSUANCE COSTS, NET	16,831,376	13,819,195
TOTAL ASSETS	$ 1,001,236,168	$ 2,026,746,332
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
CURRENT LIABILITIES		
Accounts Payable	$ 98,885,559	$ 231,557,547
Accrued Expenses	6,266,474	6,653,124
Accrued Interest	19,358,330	3,585,536
Derivative Instruments	678	-
Deferred Tax Liability	31,695,562	43,938,000
Asset Retirement Obligations	212,269	-
Total Current Liabilities	156,418,872	285,734,207
LONG-TERM LIABILITIES		
Revolving Credit Facility	170,000,000	298,000,000
8% Senior Notes	697,676,782	508,053,097
Derivative Instruments	-	579,070

Asset Retirement Obligations	5,482,237	5,105,762
Deferred Tax Liability	-	158,412,555
Total Long-Term Liabilities	873,159,019	970,150,484
TOTAL LIABILITIES	1,029,577,891	1,255,884,691
COMMITMENTS AND CONTINGENCIES (NOTE 8)		
STOCKHOLDERS' EQUITY (DEFICIT)		
Preferred Stock, Par Value $.001; 5,000,000 Authorized, No Shares Outstanding	-	-
Common Stock, Par Value $.001; 95,000,000 Authorized (9/30/2015 – 61,600,803 Shares Outstanding and 12/31/2014 – 61,066,712 Shares Outstanding)	61,601	61,067
Additional Paid-In Capital	437,169,607	433,332,285
Retained Earnings (Deficit)	(465,572,931)	337,468,289
Total Stockholders' Equity (Deficit)	(28,341,723)	770,861,641
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 1,001,236,168	$ 2,026,746,332

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 NINE MONTHS ENDED SEPTEMBER 30, 2015 AND 2014
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
REVENUES				
Oil and Gas Sales	$49,779,903	$119,191,594	$163,298,384	$337,149,610
Gain on Derivative Instruments, Net	51,366,762	61,583,301	54,818,997	349,335
Other Revenue	9,887	2,594	27,004	5,863
Total Revenues	101,156,552	180,777,489	218,144,385	337,504,808
OPERATING EXPENSES				
Production Expenses	12,567,423	14,717,257	40,331,314	39,428,008
Production Taxes	5,048,227	12,068,494	17,333,123	34,073,083
General and Administrative Expense	4,614,771	4,698,972	13,224,012	12,677,481
Depletion, Depreciation, Amortization and Accretion	31,670,479	45,646,232	113,629,323	123,959,402
Impairment of Oil and Natural Gas Properties	354,422,654	-	996,815,713	-
Total Expenses	408,323,554	77,130,955	1,181,333,485	210,137,974
INCOME (LOSS) FROM OPERATIONS	(307,167,002)	103,646,534	(963,189,100)	127,366,834
OTHER INCOME (EXPENSE)				
Interest Expense, Net of Capitalization	(16,154,160)	(10,624,246)	(42,278,400)	(30,850,004)
Other Income (Expense)	1,586	13,022	2,128	45,794
Total Other Income (Expense)	(16,152,574)	(10,611,224)	(42,276,272)	(30,804,210)
INCOME (LOSS) BEFORE INCOME TAXES	(323,319,576)	93,035,310	(1,005,465,372)	96,562,624
INCOME TAX PROVISION (BENEFIT)	(77,544)	35,050,000	(202,424,154)	36,400,000
NET INCOME (LOSS)	$(323,242,032)	$57,985,310	$(803,041,218)	$60,162,624
Net Income (Loss) Per Common Share – Basic	$(5.33)	$0.96	$(13.25)	$0.99
Net Income (Loss) Per Common Share – Diluted	$(5.33)	$0.95	$(13.25)	$0.99
Weighted Average Shares Outstanding – Basic	60,679,257	60,559,827	60,627,142	60,753,752
Weighted Average Shares Outstanding – Diluted	60,679,257	60,736,502	60,627,142	60,950,641

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF CASH FLOWS
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2015 AND 2014
(UNAUDITED)

	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (Loss)	$(803,041,218)	$60,162,624
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Depletion, Depreciation, Amortization and Accretion	113,629,323	123,959,402
Amortization of Debt Issuance Costs	2,674,927	2,053,879
Amortization of 8% Senior Notes Premium	(376,315)	(1,115,044)
Deferred Income Taxes	(202,350,555)	36,400,000
Loss (Gain) on the Mark-to-Market of Derivative Instruments	59,115,913	(25,433,684)
Amortization of Deferred Rent	(8,548)	(10,990)
Share-Based Compensation Expense	2,911,715	2,022,243
Impairment of Oil and Natural Gas Properties	996,815,713	-
Other	975,556	-
Changes in Working Capital and Other Items:		
Trade Receivables	(5,361,872)	(1,758,497)
Prepaid Expenses and Other	24,395	(1,021,830)
Accounts Payable	(4,450,439)	2,805,152
Accrued Interest	15,007,861	9,016,690
Accrued Expenses	(688,101)	2,290,764
Asset Retirement Obligations	(57,345)	-
Net Cash Provided By Operating Activities	174,821,010	209,370,709
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of Oil and Natural Gas Properties and Development Capital Expenditures, Net	(233,364,628)	(345,269,233)
Proceeds from Sale of Oil and Natural Gas Properties	160,944	-
Purchases of Other Property and Equipment	(20,859)	(80,279)
Net Cash Used for Investing Activities	(233,224,543)	(345,349,512)
CASH FLOWS FROM FINANCING ACTIVITIES		
Advances on Revolving Credit Facility	140,000,000	163,000,000
Repayments on Revolving Credit Facility	(268,000,000)	(10,000,000)
Debt Issuance Costs Paid	(5,687,108)	(434,936)
Issuance of Senior Unsecured Notes	190,000,000	-
Repurchase of Common Stock – Tax Obligations	(204,613)	(14,224,260)
Net Cash Provided by Financing Activities	56,108,279	138,340,804
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(2,295,254)	2,362,001
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	9,337,512	5,687,166

CASH AND CASH EQUIVALENTS – END OF PERIOD	$7,042,258	$8,049,167
Supplemental Disclosure of Cash Flow Information		
Cash Paid During the Period for Interest	$25,412,729	$23,201,544
Cash Paid During the Period for Income Taxes	$3,303,945	$-
Non-Cash Financing and Investing Activities:		
Oil and Natural Gas Properties Included in Accounts Payable	$92,962,284	$211,194,448
Capitalized Asset Retirement Obligations	$364,913	$739,591
Non-Cash Compensation Capitalized on Oil and Gas Properties	$465,198	$521,640

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

NOTES TO CONDENSED FINANCIAL STATEMENTS
SEPTEMBER 30, 2015
(UNAUDITED)

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

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

Northern's principal business is crude oil and natural gas exploration, development, and production with operations in North Dakota and Montana that primarily target the Bakken and Three Forks formations in the Williston Basin of the United States. The Company acquires leasehold interests that comprise of non-operated working interests in wells and in drilling projects within its area of operations. As of September 30, 2015, approximately 70% of Northern's 169,020 total net acres were developed.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The financial information included herein is unaudited, except for the balance sheet as of December 31, 2014, which has been derived from the Company's audited financial statements for the year ended December 31, 2014. However, such information includes all adjustments (consisting of normal recurring adjustments and change in accounting principles) that 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 ("GAAP") have been condensed or omitted in this Form 10-Q pursuant to certain rules and regulations of the Securities and Exchange Commission ("SEC"). The condensed financial statements should be read in conjunction with the audited financial statements for the year ended December 31, 2014, which were included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

Use of Estimates

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

Cash and Cash Equivalents

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

Accounts Receivable

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

The allowance for doubtful accounts at September 30, 2015 and December 31, 2014 was $4.5 million and $1.8 million, respectively.

Advances to Operators

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

Other Property and Equipment

Property and equipment that are not crude oil and natural gas properties are recorded at cost and depreciated using the straight-line method over their estimated useful lives of three to seven years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than crude oil and natural gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The Company has not recognized any impairment losses on non-crude oil and natural gas long-lived assets. Depreciation expense was $74,469 and $78,414 for the three months ended September 30, 2015 and 2014, respectively. Depreciation expense was $229,694 and $238,168 for the nine months ended September 30, 2015 and 2014, respectively.

Oil and Gas Properties

Northern follows the full cost method of accounting for crude oil and natural gas operations whereby all costs related to the exploration and development of crude oil and natural gas properties are capitalized into a single cost center (“full cost pool”). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition, and exploration activities. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to the production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred. Capitalized costs are summarized as follows for the three and nine months ended September 30, 2015 and 2014, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Capitalized Certain Payroll and Other Internal Costs	$520,046	$842,641	$1,500,734	$1,839,206
Capitalized Interest Costs	311,739	1,137,655	1,270,420	3,476,446
Total	$831,785	$1,980,296	$2,771,154	$5,315,652

As of September 30, 2015, the Company held leasehold interests in the Williston Basin on acreage located in North Dakota and Montana targeting the Bakken and Three Forks formations.

Proceeds from property sales will generally be credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full cost pool. There were no property sales in the nine months ended September 30, 2015 and 2014 that resulted in a significant alteration.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives designated as hedges for accounting purposes, if any, that hedge the Company's oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or non-cash writedown is required.

As a result of currently prevailing low commodity prices and their effect on the proved reserve values of properties in 2015, we recorded non-cash ceiling test impairments for the three- and nine-month periods ended September 30, 2015 of $354.4 million and $996.8 million, respectively. The Company did not have any impairment of its proved oil and gas properties during 2014. The impairment charge affected our reported net income but did not reduce our cash flow. Continued write downs of oil and natural gas properties are expected to occur until such time as commodity prices have stabilized or recovered long enough to stabilize or increase the trailing 12-month average price used in the ceiling calculation. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Capitalized costs associated with impaired properties and capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs, are depleted and amortized on the unit-of-production method. Under this method, depletion is calculated at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the period. 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 three months ended September 30, 2015 and 2014, the Company transferred into the full cost pool costs related to expired leases of $6.4 million and $7.8 million, respectively. For the nine months ended September 30, 2015 and 2014, the Company transferred into the full cost pool costs related to expired leases of $15.3 million and $20.0 million, respectively.

Asset Retirement Obligations

The Company accounts for its abandonment and restoration liabilities under FASB ASC Topic 410, "Asset Retirement and Environmental Obligations" ("FASB ASC 410"), which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Debt Issuance Costs

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

The amortization of debt issuance costs for the three months ended September 30, 2015 and 2014 was $1.0 million and $0.7 million, respectively. The amortization of debt issuance costs for the nine months ended September 30, 2015 and 2014 was $2.7 million and $2.1 million, respectively.

Bond Premium/Discount on Senior Notes

On May 13, 2013, the Company recorded a bond premium of $10.5 million in connection with the “8% Senior Notes Due 2020” (see Note 4). This bond premium is being amortized over the term of the related financing using the straight-line method, which approximates the effective interest method. The amortization of the bond premium for the three months ended September 30, 2015 and 2014 was $0.4 million in each period. The amortization of the bond premium for the nine months ended September 30, 2015 and 2014 was $1.1 million in each period.

On May 18, 2015, the Company recorded a bond discount of $10.0 million in connection with the “8% Senior Notes Due 2020” (see Note 4). This bond discount is being amortized over the term of the related financing using the straight-line method, which approximates the effective interest method. The amortization of the bond discount for the three months ended September 30, 2015 and 2014 was $0.5 million and $0, respectively. The amortization of the bond premium for the nine months ended September 30, 2015 and 2014 was $0.7 million and $0, respectively.

Revenue Recognition

The Company recognizes crude oil and natural gas revenues from its interests in producing wells when production is delivered to, and title has transferred to, the purchaser and to the extent the selling price is reasonably determinable. The Company uses the sales method of accounting for natural gas balancing of natural gas production and would recognize a liability if the existing proven reserves were not adequate to cover the current imbalance situation. For the nine months ended September 30, 2015 and 2014, the Company’s natural gas production was in balance, meaning its cumulative portion of natural gas production taken and sold from wells in which it has an interest equaled its entitled interest in natural gas production from those wells.

Concentrations of Market and Credit Risk

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

The Company operates in the exploration, development and production sector of the crude oil and natural gas industry. The Company’s receivables include amounts due from purchasers of its crude oil and natural gas production. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the crude oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company’s results of operations over the long-term.

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

Restructuring Costs

The Company accounts for restructuring costs in accordance with FASB ASC Topic 420 "Exit or Disposal Cost Obligations." Under these standards, the costs associated with restructuring are recorded during the period in which the liability is incurred. During the three-and nine-month periods ended September 30, 2015, we recognized $0.5 million in restructuring costs for employee severance and related benefit costs incurred as part of a reduction in workforce and the closing of our Denver office, which includes $0.1 million of non-cash expense related to acceleration of certain equity awards previously granted under our 2013 Incentive Plan.

Stock-Based Compensation

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

Stock Issuance

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

Income Taxes

The Company's income tax expense, deferred tax assets and deferred tax liabilities reflect management's best assessment of estimated current and future taxes to be paid. The Company estimates for each interim reporting period the effective tax rate expected for the full fiscal year and uses that estimated rate in providing for income taxes on a current year-to-date basis. The Company's only taxing jurisdiction is the United States (federal and state).

Deferred income taxes arise from temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements, which will result in taxable or deductible amounts in the future. In evaluating the Company's ability to recover its deferred tax assets, the Company considers all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax-planning strategies, and results of recent operations. In projecting future taxable income, the Company begins with historical results and incorporates assumptions about the amount of future state and federal pretax operating income adjusted for items that do not have tax consequences. The assumptions about future taxable income require significant judgment and are consistent with the plans and estimates the Company is using to manage the underlying businesses.

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. In assessing the need for a valuation allowance for the Company's deferred tax assets, a significant item of negative evidence considered was the cumulative book loss over the three-year period ended September 30, 2015, driven primarily by the full cost ceiling impairments over that period. Additionally, the Company's revenue, profitability and future growth are substantially dependent upon prevailing and future prices for oil and natural gas. The markets for these commodities continue to be volatile. Changes in oil and natural gas prices have a significant impact on the value of the Company's reserves and on its cash flows. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas and a variety of additional factors that are beyond the Company's control. Due to these factors, management has placed a lower weight on the prospect of future earnings in its overall analysis of the valuation allowance.

In determining whether to establish a valuation allowance on the Company's deferred tax assets, management concluded that the objectively verifiable evidence of cumulative negative earnings for the three-year period ended September 30, 2015, is difficult to overcome with any forms of positive evidence that may exist. Accordingly, the valuation allowance against the Company's deferred tax asset at September 30, 2015 was $170.0 million. No valuation allowance was recorded at December 31, 2014.

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 nine months ended September 30, 2015 and 2014 are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Weighted Average Common Shares Outstanding – Basic	60,679,257	60,559,827	60,627,142	60,753,752
Plus: Potentially Dilutive Common Shares Including Stock Options and Restricted Stock	-	176,675	-	196,889
Weighted Average Common Shares Outstanding – Diluted	60,679,257	60,736,502	60,627,142	60,950,641
Restricted Stock Excluded From EPS Due To The Anti-Dilutive Effect	150,428	5,064	173,763	6,346

Derivative Instruments and Price Risk Management

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

The Company follows the provisions of FASB ASC 815, "Derivatives and Hedging" as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value and marked-to-market at the end of each period. Any realized gains and losses are recorded to gain (loss) on settled derivatives and mark-to-market gains or losses are recorded to gains (losses) on the mark-to-market of derivative instruments on the condensed statements of operations. See Note 11 for a description of the derivative contracts which the Company has entered into.

New Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board ("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.

In May 2014, the FASB issued ASU No. 2014-09 "Revenue from Contracts with Customers," which provides guidance for revenue recognition. The standard's core principle is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This guidance will be effective for the Company in the annual period beginning after December 15, 2016. However, the FASB recently announced plans to defer the effective date of ASU No. 2014-09 for one year. The Company is evaluating the effect of adopting this new accounting guidance but does not expect adoption will have a material impact on the Company's statements of operations, balance sheets, cash flows or disclosures.

In August 2014, the FASB issued ASU No. 2014-15, "Presentation of Financial Statements - Going Concern (Subtopic 205-40)." The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for the annual period beginning after December 15, 2016 and for annual and interim periods thereafter. Early adoption is permitted. The Company does not believe that the adoption of this guidance will have a material impact on its financial statements.

In April 2015, the FASB issued ASU No. 2015-03, “Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs,” that requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update. An entity is required to apply ASU 2015-03 for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. An entity should apply ASU 2015-03 on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. Upon transition, an entity is required to comply with the applicable disclosures for a change in an accounting principle. These disclosures include the nature of and reason for the change in accounting principle, the transition method, a description of the prior-period information that has been retrospectively adjusted, and the effect of the change on the financial statement line items. We are evaluating the impact that this new guidance will have on our financial statements.

NOTE 3 CRUDE OIL AND NATURAL GAS PROPERTIES

The value of the Company's crude oil and natural gas properties consists of all acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying condensed statements of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets based on their estimated fair value at the time of the acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities. Development capital expenditures and purchases of properties that were in accounts payable and not yet paid in cash at September 30, 2015 and December 31, 2014 were approximately $93.0 million and $221.3 million, respectively.

Acquisitions

For the nine months ended September 30, 2015, the Company acquired approximately 3,157 net acres, for an average cost of approximately $1,065 per net acre, in its key prospect areas in the form of effective leases.

For the nine months ended September 30, 2014, the Company acquired approximately 17,050 net acres, for an average cost of approximately $1,586 per net acre, in its key prospect areas in the form of effective leases.

Unproved Properties

Unproved properties not being amortized comprise approximately 41,348 net acres and 55,743 net acres of undeveloped leasehold interests at September 30, 2015 and December 31, 2014, respectively. The Company believes that the majority of its unproved costs will become subject to depletion within the next five years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of its reserves.

All properties that are not classified as proved properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion. Once a property is classified as proved, all associated acreage and drilling costs are subject to depletion.

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

The Company assesses all items classified as unproved property on an annual basis, or if certain circumstances exist, more frequently, for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and amortization. During the third quarter of 2015 and 2014, the Company included in the pool of cost subject to depletion $1.1 million and $0, respectively, for unproved property costs related to expiring leases. For the nine months ended September 30, 2015 and 2014, the Company included in the pool of cost subject to depletion $32.4 million and $0, respectively, for unproved property costs related to expiring leases.

NOTE 4 REVOLVING CREDIT FACILITY AND LONG-TERM DEBT

Revolving Credit Facility

In February 2012, the Company entered into an amended and restated credit agreement providing for a revolving credit facility (the "Revolving Credit Facility"), which replaced its previous revolving credit facility with a syndicated facility. The Revolving Credit Facility, which is secured by substantially all of the Company's assets, provides for a commitment equal to the lesser of the facility amount or the borrowing base. At September 30, 2015, the facility amount was $750 million, the borrowing base was $550 million and there was a $170 million outstanding balance, leaving $380 million of borrowing capacity available under the facility. In October 2015, the borrowing base was reaffirmed at $550 million.

The Revolving Credit Facility matures on September 30, 2018 and provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. Borrowings under the Revolving Credit Facility can either be at the Alternate Base Rate (as defined in the credit agreement) plus a spread ranging from 0.5% to 1.5% or LIBOR borrowings at the Adjusted LIBOR Rate (as defined in the credit agreement) plus a spread ranging from 1.5% to 2.5%. The applicable spread at any time is dependent upon the amount of borrowings relative to the borrowing base at such time. The Company may elect, from time to time, to convert all or any part of its LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. A commitment fee is paid on the undrawn balance based on an annual rate of either 0.375% or 0.50%. At September 30, 2015, the commitment fee was 0.375% and the interest rate margin was 1.75% on LIBOR loans and 0.75% on base rate loans. At September 30, 2015, the Company had $170 million of LIBOR loans issued under the Revolving Credit Facility at a weighted average interest rate of 1.96%. The Company was in compliance with the financial covenants of the Revolving Credit Facility at September 30, 2015.

The Revolving Credit Facility contains negative covenants that limit the Company's ability, among other things, to pay any cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of its business or operations, merge, consolidate, or make investments. In addition, the Company is required to maintain a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0, a ratio of secured debt to EBITDAX (as defined in the credit agreement) of no greater than 2.5 to 1.0 and a ratio of EBITDAX (as defined in the credit agreement) to interest expense (as defined in the credit agreement) of no less than 2.5 to 1.0.

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

8.000% Senior Notes Due 2020

On May 18, 2012, the Company issued at par value $300 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "Original Notes"). On May 13, 2013, the Company issued at a price of 105.25% or par an additional $200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "2013 Follow-on Notes"). On May 18, 2015, the Company issued at a price of 95.000% of par an additional $200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "2015 Mirror Notes" and, together with the Original Notes and the 2013 Follow-on Notes, the "Notes"). Interest is payable on the Notes semi-annually in arrears on each of June 1 and December 1. The Company currently does not have any subsidiaries and, as a result, the Notes are not currently guaranteed. Any subsidiaries the Company forms in the future may be required to unconditionally guarantee, jointly and severally, payment obligation under the Notes on a senior unsecured basis. The issuance of the Original Notes resulted in net proceeds to the Company of approximately $291.2 million, the issuance of the 2013 Follow-on Notes resulted in net proceeds to the Company of approximately $200.1 million, and the issuance of the 2015 Mirror Notes resulted in net proceeds to the Company of approximately $184.9 million. Collectively, the net proceeds are in use to fund the Company's exploration, development and acquisition program and for general corporate purposes (including repayment of borrowings that were outstanding under the Revolving Credit Facility at the time the Notes were issued).

Prior to June 1, 2016, the Company may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after June 1, 2016, the Company may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104% for the twelve-month period beginning on June 1, 2016, 102% for the twelve-month period beginning June 1, 2017 and 100% beginning on June 1, 2018, plus accrued and unpaid interest to the redemption date.

The Original Notes and the 2013 Follow-on Notes are governed by an Indenture, dated as of May 18, 2012, by and among the Company and Wilmington Trust, National Association (the "Original Indenture"). The 2015 Mirror Notes are governed by an Indenture, dated as of May 18, 2015, by and among the Company and Wilmington Trust, National Association (the "Mirror Indenture"). The terms and conditions of the Mirror Indenture conform, in all material respects, to the terms and conditions set forth in the Original Indenture. As such, the Mirror Indenture, together with the Original Indenture, are referred to herein as the "Indenture."

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

The Indenture contains customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal of or premium, if any, on any Note when due;
- failure by the Company to comply with its other obligations under the Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and certain of its subsidiaries, if any, in the aggregate principal amount of $25 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary;
- failure by the Company or any significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary to pay certain final judgments aggregating in excess of $25 million within 60 days; and
- any guarantee of the Notes by a guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

NOTE 5 COMMON AND PREFERRED STOCK

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

Common Stock

The following is a schedule of changes in the number of shares of common stock outstanding during the nine months ended September 30, 2015 and the year ended December 31, 2014:

	Nine Months Ended September 30, 2015	Year Ended December 31, 2014
Beginning Balance	61,066,712	61,858,199
Stock Options Exercised	-	100,000
Restricted Stock Grants (Note 6)	565,039	299,416
Stock Repurchased	-	(1,153,885)
Other Surrenders	(29,551)	(79,461)
Other	(1,397)	42,443
Ending Balance	61,600,803	61,066,712

2015 Activity

In the nine months ended September 30, 2015, 29,551 shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately $205,000, which was based on the market prices on the dates the shares were surrendered.

Stock Repurchase Program

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

During the first nine months of 2015, the Company did not repurchase shares of its common stock under the stock repurchase program. In 2014, the Company repurchased 1,153,885 shares of its common stock under the stock repurchase program. This stock had a cost of approximately $15.5 million. All repurchased shares are included in the Company's pool of authorized but unissued shares. The Company's accounting policy upon the repurchase of shares is to deduct its par value from Common Stock and to reflect any excess of cost over par value as a deduction from Additional Paid-in Capital.

Performance Equity Awards

The Company has granted performance equity awards under its 2015 Long Term Incentive Program to certain officers. The awards are subject to a market condition, which is based on a comparison of the Company versus a defined peer group with respect to year-over-year change in average stock price from 2014 to 2015. Depending on the Company's stock price performance relative to the defined peer group, the award recipients will earn between 0% and 150% of their 2015 base salaries and will be settled in restricted shares of the Company's common stock that will vest over a three-year service-based period beginning in 2016.

The Company used a Monte Carlo simulation model to estimate the fair value of the awards based on the expected outcome of the Company's stock price performance relative to the defined peer group using key valuation assumptions. The assumptions used for the Monte Carlo model to determine the fair value of the awards and associated compensation expense included a forecast period of one year, a risk-free interest rate of 0.11% and 44% for Northern's stock price volatility.

The maximum value of the performance shares issuable if all participants earned the maximum award would total $2.9 million. For the three- and nine-month periods ended September 30, 2015, the Company recorded $0.2 million and $0.3 million, respectively, of compensation expense in connection with these performance awards.

NOTE 6 STOCK OPTIONS/STOCK-BASED COMPENSATION AND WARRANTS

The Company maintains its 2013 Incentive Plan (the "2013 Plan") to provide a means whereby the Company may be able, by granting equity and other types of awards, to attract, retain and motivate capable and loyal employees, non-employee directors, consultants and advisors of the Company, for the benefit of the Company and its shareholders. In May 2015, the Company's shareholders approved an amendment to the 2013 Plan to increase the number of shares available for awards under the 2013 Plan by 2.5 million shares. As a result, as of September 30, 2015, there were 3,729,177 shares available for future awards under the 2013 Plan.

Restricted Stock Awards

During the nine months ended September 30, 2015, the Company issued 565,039 restricted shares of common stock under the 2013 Plan as compensation to officers, employees and directors of the Company. Unvested restricted shares vest over various terms with all restricted shares vesting no later than October 2018. As of September 30, 2015, there was approximately $6.3 million of total unrecognized compensation expense related to unvested restricted stock that will be recognized over a weighted-average period of approximately 2.0 years. The Company has assumed a zero percent forfeiture rate for restricted stock due to the small number of officers, employees and directors that have received restricted stock awards.

The following table reflects the outstanding restricted stock awards and activity related thereto for the nine months ended September 30, 2015:

	Nine Months Ended September 30, 2015	
	Number of Shares	Weighted-Average Price
Restricted Stock Awards:		
Restricted Shares Outstanding at Beginning of Period	538,499	$ 13.54
Shares Granted	565,039	8.65
Lapse of Restrictions	(201,216)	12.99
Shares Forfeited	(1,397)	14.79
Restricted Shares Outstanding at End of Period	900,925	$ 10.42

Stock Option Awards

On November 1, 2007, the board of directors granted options to purchase 560,000 shares of the Company's common stock under the Company's 2006 Incentive Stock Option Plan. The Company granted options to purchase 500,000 shares of the Company's common stock to members of the board and options to purchase 60,000 shares of the Company's common stock to one employee pursuant to an employment agreement. These options were granted at a price of $5.18 per share and the optionees were fully vested on the grant date. As of September 30, 2015, options to purchase a total of 141,872 shares of the Company's common stock remain outstanding but unexercised. The board of directors determined that no future grants will be made pursuant to the 2006 Incentive Stock Option Plan.

The Company used the Black-Scholes option valuation model to calculate stock-based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. The Company used the simplified method to determine the expected term of the options due to the lack of sufficient historical data. Changes in these assumptions can materially affect the fair value estimate. The total fair value of the options is recognized as compensation over the vesting period. There were no stock options granted by the Company in the nine months ended September 30, 2015.

Currently Outstanding Options

- No options were forfeited during the nine months ended September 30, 2015.
- No options expired during the nine months ended September 30, 2015.
- Options covering 141,872 shares were exercisable and outstanding at September 30, 2015.
- The Company recorded no compensation expense related to these options for the nine months ended September 30, 2015. There is no further compensation expense that will be recognized in future periods relative to any options

that had been granted as of September 30, 2015, because the Company recognized the entire fair value of such compensation upon vesting of the options.

- There were no unvested options at September 30, 2015.

NOTE 7 RELATED PARTY TRANSACTIONS

The Company is a non-operating participant in a number of wells in North Dakota that are operated by Emerald Oil, Inc. (“Emerald”), by virtue of leased acreage or working interests held by the Company in drilling units operated by Emerald. As of September 30, 2015, such wells included 48 gross (8.1 net) producing wells, and an additional 0 gross (0.0 net) wells that were drilling or awaiting completion. Through September 30, 2015, Northern has incurred $86.2 million in connection with its working interest in these wells. James Russell (J.R.) Reger is a current director (and until March 2014 was an executive officer) of Emerald, which is a publicly-traded company. J.R. Reger is also the brother of Northern Oil’s Chairman and Chief Executive Officer, Michael Reger. At September 30, 2015, the Company’s accounts receivable and accounts payable balances with Emerald were $1.5 million and $2.1 million, respectively. At December 31, 2014, the Company’s accounts receivable and accounts payable balances with Emerald were $2.9 million and $8.4 million, respectively. The Company recorded total revenues of $7.1 million and $18.7 million from Emerald for the nine months ended September 30, 2015 and 2014, respectively.

All transactions involving related parties are approved or ratified by the Company’s Audit Committee.

NOTE 8 COMMITMENTS & CONTINGENCIES

Litigation

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

The Company is party to a quiet title action in North Dakota that relates to its interest in certain crude oil and natural gas leases. In the event the action results in a final judgment that is adverse to the Company, the Company would be required to reverse approximately $1.7 million in revenue (net of accrued taxes) that has been accrued since the second quarter of 2008 based on the Company’s purported interest in the crude oil and natural gas leases at issue, approximately $47,000 of which relates to the nine-month period ended September 30, 2015. The Company fully maintains the validity of its interest in the crude oil and natural gas leases, and is vigorously defending such interest.

NOTE 9 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. A valuation allowance for the Company’s deferred tax assets is established if, in management’s opinion, it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. At September 30, 2015, a valuation allowance of $170.0 million had been provided for our net deferred tax assets based on the uncertainty regarding whether these assets may 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 (benefit) for the three and nine months ended September 30, 2015 and 2014 consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Current Income Taxes (Benefit)	$(77,544)	$-	$(73,599)	$-
Deferred Income Taxes (Benefit)				
Federal	(116,171,555)	32,562,000	(360,106,555)	33,797,000
State	(3,964,000)	2,488,000	(12,287,000)	2,603,000
Valuation Allowance	120,135,555	-	170,043,000	-
Total Provision (Benefit)	$(77,544)	$35,050,000	$(202,424,154)	$36,400,000

Income tax provision (benefit) during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income (loss), plus any unusual or infrequently occurring items that are recorded in the interim period. The provision for the three- and nine-month periods ended September 30, 2015, presented above, differ from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% to income before income taxes. The lower effective tax rate in 2015 relates to the valuation allowance placed on the net deferred tax asset in 2015, in addition to state income taxes and estimated permanent differences. The higher effective tax rate in 2014 relates to the addition of state income taxes and estimated permanent differences.

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 three and nine months ended September 30, 2015 and 2014, the Company did not recognize any interest or penalties in its condensed statements of operations, nor did it have any interest or penalties accrued in its condensed balance sheet at September 30, 2015 and December 31, 2014 relating to unrecognized benefits.

The tax years 2014, 2013, 2012 and 2011 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which the Company is subject.

NOTE 10 FAIR VALUE

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

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

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

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

Financial Assets and Liabilities

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company’s financial assets and liabilities that were accounted for at fair value on a recurring basis:

	Fair Value Measurements at September 30, 2015 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Asset (crude oil swaps)	$-	$87,881,527	$ -
Commodity Derivatives – Non-Current Asset (crude oil swaps)	-	6,330,398	-
Commodity Derivatives – Current Liability (crude oil swaptions)	-	(678)	-
Total	$-	$94,211,247	$ -

	Fair Value Measurements at December 31, 2014 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Asset (crude oil swaps)	$-	$128,893,220	$ -
Commodity Derivatives – Non-Current Asset (crude oil swaps)	-	25,013,011	-
Commodity Derivatives – Non-Current Liability (crude oil swaptions)	-	(579,070)	-
Total	$-	$153,327,161	$ -

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include crude oil swaps and crude oil swaptions (see Note 11). The fair value of the Company's derivative financial instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of all derivative contracts is reflected on the condensed balance sheet. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

Fair Value of Other Financial Instruments

The Company's financial instruments, including certain cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments.

The carrying amount of the Company's long-term debt reported in the condensed balance sheet at September 30, 2015 is $867.7 million, which includes $697.7 million of senior unsecured notes including a net discount of $2.3 million and $170.0 million of borrowings under the Company's revolving credit facility (see Note 4). The fair value of the Company's senior unsecured notes, which are publicly traded, is $526.5 million at September 30, 2015. The

Company’s revolving credit facility approximates its fair value because of its floating rate structure.

Non-Financial Assets and Liabilities

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC 410. The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligations liability is deemed to use Level 3 inputs. Asset retirement obligations incurred during the nine months ended September 30, 2015 were approximately $0.4 million.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. There were no transfers of financial assets or liabilities between Level 1, Level 2 or Level 3 inputs for the nine-month period ended September 30, 2015.

NOTE 11 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes commodity swap contracts, swaptions and 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.

All derivative instruments are recorded on the Company’s balance sheet as either assets or liabilities measured at their fair value (see Note 10). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value are recognized in the revenues section of the Company’s condensed statements of operations as a gain or loss on derivative instruments. Mark-to-market gains and losses represent changes in fair values of derivatives that have not been settled. The Company’s cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company’s derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

The following table presents cash settlements on matured or liquidated derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented. Cash receipts and payments below reflect proceeds received upon early liquidation of derivative positions and gains or losses on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continue to be held at period-end and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured or were liquidated during the period.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Cash Received (Paid) on Derivatives:				
Crude Oil Fixed Price Swaps	$42,958,080	$(6,950,759)	$113,732,460	$(24,719,289)
Crude Oil Collars (1)	-	(66,840)	202,450	(365,060)
Cash Received (Paid) on Derivatives, Net	42,958,080	(7,017,599)	113,934,910	(25,084,349)

Non-Cash Gain (Loss) on Derivatives:				
Crude Oil Fixed Price Swaps	8,408,682	67,863,469	(59,115,913)	25,346,339
Crude Oil Collars	-	737,431	-	87,345
Non-Cash Gain (Loss) on Derivatives, Net	8,408,682	68,600,900	(59,115,913)	25,433,684
Gain on Derivative Instruments, Net	$51,366,762	$61,583,301	$54,818,997	$349,335

(1) Net cash receipts for crude oil collars for the three- and nine-month periods ended September 30, 2015 include approximately $202,000 of proceeds received from crude oil derivative contracts that were settled in the second quarter of 2015 prior to their contractual maturities.

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

The following table reflects open commodity swap contracts as of September 30, 2015, the associated volumes and the corresponding fixed price.

Settlement Period	Oil (Barrels)	Fixed Price ($)
Swaps-Crude Oil		
10/01/15 – 12/31/15	180,000	89.00
10/01/15 – 12/31/15	90,000	89.00
10/01/15 – 12/31/15	90,000	89.02
10/01/15 – 12/31/15	45,000	89.00
10/01/15 – 12/31/15	45,000	89.00
10/01/15 – 12/31/15(1)	90,000	90.75
10/01/15 – 12/31/15(1)	90,000	91.00
10/01/15 – 12/31/15(1)	90,000	91.25
10/01/15 – 06/30/16	270,000	89.00
10/01/15 – 06/30/16	270,000	90.00
10/01/15 – 06/30/16	270,000	91.00
01/01/16 – 06/30/16	180,000	90.00
01/01/16 – 06/30/16	90,000	90.00
01/01/16 – 06/30/16	90,000	90.00
07/01/16 – 12/31/16	180,000	65.00
07/01/16 – 12/31/16	180,000	64.93
07/01/16 – 12/31/16	90,000	65.00
07/01/16 – 12/31/16	180,000	65.00
07/01/16 – 12/31/16	180,000	64.93
07/01/16 – 12/31/16	90,000	65.30

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(1) The Company has entered into crude oil derivative contracts that give counterparties the option to extend certain current derivative contracts for an additional six-month period. Options covering a notional volume of 90,000 barrels per month are exercisable on or about December 31, 2015. If the counterparties exercise all such options, the notional volume of the Company's existing crude oil derivative contracts will increase by 90,000 barrels per month at an average price of $91.00 per barrel for each month during the period January 1, 2016 through June 30, 2016.

As of September 30, 2015, the Company had a total volume on open commodity swaps of 2.8 million barrels at a weighted average price of approximately $81.87 per barrel.

The following table reflects the weighted average price of open commodity swap derivative contracts as of September 30, 2015, by year with associated volumes.

Weighted Average Price
Of Open Commodity Swap Contracts

Year	Weighted

	Volumes (Bbl)	Average Price ($)
2015	990,000	89.82
2016	1,800,000	77.50

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at September 30, 2015 and December 31, 2014, respectively. Certain amounts may be presented on a net basis on the condensed financial statements when such amounts are with the same counterparty and subject to a master netting arrangement:

Type of Crude Oil Contract	Balance Sheet Location	September 30, 2015 Estimated Fair Value	December 31, 2014 Estimated Fair Value
Derivative Assets:			
Swap Contracts	Current Assets	$ 87,881,527	$ 128,893,220
Swap Contracts	Non-Current Assets	6,330,398	25,013,011
Total Derivative Assets		$ 94,211,925	$ 153,906,231
Derivative Liabilities:			
Swaption Contracts	Current Liabilities	$ (678)	$ -
Swaption Contracts	Non-Current Liabilities	-	(579,070)
Total Derivative Liabilities		$ (678)	$ (579,070)

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

	Estimated Fair Value at September 30, 2015		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 87,881,527	$ -	$ 87,881,527
Non-Current Assets	6,330,398	-	6,330,398
Total Derivative Assets	$ 94,211,925	$ -	$ 94,211,925
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (678)	$ -	$ (678)
Non-Current Liabilities	-	-	-
Total Derivative Liabilities	$ (678)	$ -	$ (678)

	Estimated Fair Value at December 31, 2014		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance	Net Amounts of Assets Presented in the Balance Sheet

				Sheet		
Offsetting of Derivative Assets:						
Current Assets	$	128,893,220	$	-	$	128,893,220
Non-Current Assets		25,013,011		-		25,013,011
Total Derivative Assets	$	153,906,231	$	-	$	153,906,231
Offsetting of Derivative Liabilities:						
Current Liabilities	$	-	$	-	$	-
Non-Current Liabilities		(579,070)		-		(579,070)
Total Derivative Liabilities	$	(579,070)	$	-	$	(579,070)

All of the Company's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements ("ISDAs") entered into with counterparties that are also lenders under the Company's Revolving Credit Facility. The Company's obligations under the derivative instruments are secured pursuant to the Revolving Credit Facility, and no additional collateral had been posted by the Company as of September 30, 2015. The ISDAs may provide that as a result of certain circumstances, such as cross-defaults, a counterparty may require all outstanding derivative instruments under an ISDA to be settled immediately. See Note 10 for the aggregate fair value of all derivative instruments that were in a net liability position at September 30, 2015 and December 31, 2014.

NOTE 12 RESTRUCTURING COSTS

In September 2015, we restructured certain of our operations in response to the current oil and gas commodity environment. These changes, which included a reduction in workforce, are expected to result in better utilization of our resources and improved cost efficiencies. We expect substantially all one-time restructuring related costs to be incurred by March 31, 2016 and do not expect these costs to materially affect our cash flows or results of operations.

Type of Restructuring Cost	Location in the Statement of Operations	Three Months Ended September 30,		Nine Months Ended September 30,	
		2015	2014	2015	2014
Severance and Benefit Costs	Operating Expenses – General and Administrative	$ 523,487	$ -	$ 523,487	$ -

The following table summarizes our restructuring costs:

Restructuring Liability at January 1, 2015	$-
Additions	523,487
Settlements	(84,431)
Revisions	-
Restructuring Liability at September 30, 2015	$439,056

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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: changes in crude oil and natural gas prices, the pace of drilling and completions activity on our properties, our ability to acquire additional development opportunities, changes in our reserves estimates or the value thereof, 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, and 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, 2014, as updated by subsequent reports we file with the SEC (including this report), which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

The following discussion should be read in conjunction with the Condensed Financial Statements and Accompanying Notes appearing elsewhere in this report.

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas properties, primarily in the Bakken and Three Forks formations within the Williston Basin in North Dakota and Montana. We believe the location, size and concentration of our acreage position in one of North America's leading unconventional oil-resource plays will provide drilling and development opportunities that result in significant long-term value. Our primary focus is oil exploration and production through non-operated working interests in wells drilled and completed in spacing units that include our acreage. Using this strategy, we had participated in over 2,589 gross (201.9 net) producing wells at September 30, 2015.

Our average daily production in the third quarter of 2015 was approximately 15,844 Boe per day, of which approximately 87% was oil. In light of the low price commodity environment, our annual capital expenditure budget declined over 70% in 2015 as compared to 2014. Despite the reduction in capital spending, our year-over-year production for the first nine months of 2015 grew 9% compared to the same period of 2014. This year-over-year production growth was driven by the completion of a larger well-in-process inventory at the beginning of 2015, as well as improved recoveries on the 24.4 net wells added to production over the last twelve months. A lower level of well completions during the quarter caused third quarter production levels to be approximately 4% lower than the same period a year ago. During the first nine months of 2015, we participated in the drilling of 251 gross (16.2 net) wells that were completed and added to production.

As of September 30, 2015, we leased approximately 169,020 net acres, of which 100% were located in the Williston Basin of North Dakota and Montana. During the quarter ended September 30, 2015, we acquired approximately 952 net mineral acres at an average cost of approximately $462 per net acre.

Source of Our Revenues

We derive our revenues from the sale of oil, natural gas and NGLs produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements. Our average realized price calculations include the effects of the settlement of all derivative contracts regardless of the accounting treatment.

Principal Components of Our Cost Structure

- Oil price differentials. The price differential between our Williston Basin well head price and the New York Mercantile Exchange ("NYMEX") WTI benchmark price is driven by the additional cost to transport oil from the Williston Basin via train, barge, pipeline or truck to refineries.

- Gain (loss) on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of oil. This account activity represents the recognition of gains and losses associated with our outstanding derivative contracts that have not been designated for hedge accounting and includes realized gains and losses on the settlement of commodity derivative instruments.

- Production expenses. Production expenses are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, salt water disposal, utilities, maintenance, repairs and servicing expenses related to our oil and natural gas properties.

- Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

- Depreciation, depletion, amortization and impairment. Depreciation, depletion, amortization, and impairment includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas properties. As a full cost company, we capitalize all costs associated with our development and acquisition efforts and allocate these costs to each unit of production using the units-of-production method.

- General and administrative expenses. General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, franchise taxes, audit and other professional fees and legal compliance.

- Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize a portion of the interest paid on applicable borrowings into our full cost pool. We include interest expense that is not capitalized into the full cost pool, the amortization of deferred financing costs and bond premiums (including origination and amendment fees), commitment fees and annual agency fees as interest expense.

- Income tax expense. Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

- the timing and success of drilling and production activities by our operating partners;
- the prices and demand for oil, natural gas and NGLs;
- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in the price of oil;
- our ability to continue to identify and acquire high-quality acreage and drilling opportunities; and
- the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of our acreage and wells in the Williston Basin subjects our operating results to factors specific to this region. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, and the limitations of the developing infrastructure and transportation capacity in this region.

The price of oil in the Williston Basin can vary depending on the market in which it is sold and the means of transportation used to transport the oil to market. Light sweet crude from the Williston Basin has a higher value at many major refining centers because of its higher quality relative to heavier and sour grades of oil; however, because of North Dakota's location relative to traditional oil transport centers, this higher value is generally offset to some extent by higher transportation costs. While rail transportation has historically been more expensive than pipeline transportation, Williston Basin prices have justified shipment by rail to markets such as St. James, Louisiana, which offers prices benchmarked to Brent/LLS. Although pipeline, truck and rail capacity in the Williston Basin has historically lagged production in growth, we believe that additional planned infrastructure growth will help keep price discounts from significantly eroding wellhead values in the region.

The price at which our oil production is sold typically reflects a discount to the NYMEX WTI benchmark price. Thus, our operating results are also affected by changes in the oil price differentials between the NYMEX WTI and the sales prices we receive for our oil production. Our oil price differential to the NYMEX WTI benchmark price during the third quarter of 2015 was $8.24 per barrel, as compared to $12.93 per barrel in the third quarter of 2014. Our oil price differential to the NYMEX WTI benchmark price during the first nine months of 2015 was $10.72 per barrel, as compared to $12.85 per barrel in the first nine months of 2014. Fluctuations in our oil price differential are due to several factors such as takeaway capacity relative to production levels in the Williston Basin, and seasonal refinery maintenance temporarily depressing crude demand. As the rail capacity continues to increase and planned pipeline expansions are completed, we believe the oil price differentials will improve.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells has varied significantly over the past few years as volatility in oil prices has significantly impacted the level of drilling activity in the Williston Basin. Generally, higher oil prices have led to increased drilling activity, with the increased demand for drilling and completion services driving these costs higher. Lower oil prices have generally had the opposite effect. In addition, individual components of the cost can vary depending on numerous factors such as the length of the horizontal lateral, the number of fracture stimulation stages, and the choice of proppant (sand or ceramic). We have seen increases in drilling and completion costs due to longer horizontal laterals and more fracture stimulation stages. In addition, the availability of well completion services has at times been constrained, resulting at times in a backlog of wells awaiting completion.

Given the significant decline in oil and gas prices that began in the second half of 2014, drilling activity in the Williston Basin has significantly reduced. North Dakota's average rig count has dropped from 190 on October 14, 2014 to 66 on October 14, 2015. The decline in drilling activity and commodity prices has recently lowered drilling costs. During the third quarter of 2015, the weighted average authorization for expenditure (or AFE) cost for wells we elected to participate in was $7.9 million, compared to $9.2 million for the wells we elected to participate in during 2014.

Market Conditions

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Being primarily an oil producer, we are more significantly impacted by changes in oil prices than by changes in the price of natural gas. World-wide supply in terms of output, especially the production quota set by OPEC, and the strength of the U.S. dollar has adversely impacted oil prices. Additionally, an economic slowdown in Europe and Asia has reduced overall demand over the second half of 2014 and has continued into 2015. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Factors impacting the future oil supply balance are world-wide demand for oil, as well as the growth in domestic oil production.

Prices for various quantities of natural gas, natural gas liquids ("NGLs") and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for natural gas and oil for the three and nine months ended September 30, 2015 and 2014.

	Three Months Ended September 30,	
	2015	2014
Average NYMEX Prices(a)		
Natural Gas (per Mcf)	$2.73	$3.95
Oil (per Bbl)	$46.50	$97.25

	Nine Months Ended September 30,	
	2015	2014
Average NYMEX Prices(a)		
Natural Gas (per Mcf)	$2.76	$4.41
Oil (per Bbl)	$51.01	$99.62

(a) Based on average NYMEX closing prices.

Oil and natural gas prices have fallen significantly since their early third quarter 2014 levels. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may materially and adversely affect our future business, financial position, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and the oil and natural gas reserves that we can economically produce. For the three-month period ended September 30, 2015, the average WTI NYMEX pricing was $46.50 per Bbl or 52% lower than the average NYMEX price per Bbl for the comparable period in 2014. If the NYMEX prices remain at these lower levels, our net revenue per Boe will decrease because we have not hedged the entire amount of anticipated production. At September 30, 2015, we have hedged 990,000 and 1,800,000 Bbls in 2015 and 2016, respectively. Lower oil and gas prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders.

Results of Operations for the three-month periods ended September 30, 2015 and September 30, 2014

The following table sets forth selected operating data for the periods indicated.

	Three Months Ended September 30, 2015	2014	% Change
Net Production:			
Oil (Bbl)	1,261,823	1,348,146	(6)
Natural Gas and NGLs (Mcf)	1,174,721	990,351	19
Total (Boe)	1,457,610	1,513,205	(4)
Net Sales:			
Oil Sales	$48,280,061	$113,681,718	(58)
Natural Gas and NGL Sales	1,499,842	5,509,876	(73)
Gain on Derivative Instruments, Net	51,366,762	61,583,301	(17)
Other Revenue	9,887	2,594	281
Total Revenues	101,156,552	180,777,489	(44)
Average Sales Prices:			
Oil (per Bbl)	$38.26	$84.32	(55)
Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl)	34.04	(5.20)	(755)
Oil Net of Settled Derivatives (per Bbl)	72.30	79.12	(9)
Natural Gas and NGLs (per Mcf)	1.28	5.56	(77)
Realized Price on a Boe Basis Including all Realized Derivative Settlements	63.62	74.13	(14)
Operating Expenses:			
Production Expenses	$12,567,423	$14,717,257	(15)
Production Taxes	5,048,227	12,068,494	(58)
General and Administrative Expense	4,614,771	4,698,972	(2)
Depletion, Depreciation, Amortization and Accretion	31,670,479	45,646,232	(31)
Impairment of Oil and Natural Gas Properties	354,422,654	-	-
Costs and Expenses (per Boe):			
Production Expenses	$8.62	$9.73	(11)
Production Taxes	3.46	7.98	(57)
General and Administrative Expense	3.17	3.11	2
Depletion, Depreciation, Amortization and Accretion	21.72	30.17	(28)
Impairment of Oil and Natural Gas Properties	243.15	-	-
Net Producing Wells at Period End	201.9	177.5	14

Oil and Natural Gas Sales

In the third quarter of 2015, oil, natural gas and NGL sales, excluding the effect of settled derivatives, decreased 58% as compared to the third quarter of 2014, driven by a 57% decrease in realized prices, excluding the effect of settled derivatives, and a 4% decrease in production. The lower average realized price in the third quarter of 2015 as compared to the same period in 2014 was principally driven by lower average NYMEX oil and gas prices, which were partially offset by a lower oil price differential. Oil price differential during the third quarter of 2015 was $8.24 per barrel, as compared to $12.93 per barrel in the third quarter of 2014.

As discussed above, we add production through drilling success as we place new wells into production and through additions from acquisitions, while we lose production due to the natural decline of oil and natural gas produced from existing wells. In light of the low price commodity environment, our annual capital expenditure budget declined over 70% in 2015 as compared to 2014. Due to lower levels of capital spending in 2015, our production volumes decreased 4% as compared to the third quarter of 2014. Production primarily decreased due to production declines that exceeded production additions from new well additions.

Derivative Instruments

We enter into derivative instruments to manage the price risk attributable to future oil production. Gain (loss) on derivative instruments, net was a gain of $51.4 million in the third quarter of 2015, compared to a gain of $61.6 million in the third quarter of 2014. Gain (loss) on derivative instruments, net is comprised of (i) cash gains and losses we recognize on settled derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on derivative instruments outstanding at period-end.

For the third quarter of 2015, we realized a gain on settled derivatives of $43.0 million, compared to a $7.0 million loss for the third quarter of 2014. Our average realized price (including all cash derivative settlements) received during the third quarter of 2015 was $63.62 per Boe compared to $74.13 per Boe in the third quarter of 2014. The gain (loss) on settled derivatives increased our average realized price per Boe by $29.47 in the third quarter of 2015 and decreased our average realized price per Boe by $4.64 in the third quarter of 2014.

As a result of forward oil price changes, we recognized a non-cash mark-to-market derivative gain of $8.4 million in the third quarter of 2015 compared to a $68.6 million gain in the third quarter of 2014. At September 30, 2015, all of our derivative contracts were recorded at their fair value, which was a net asset of $94.2 million, an increase of $86.7 million from the $7.5 million net asset recorded as of September 30, 2014.

Production Expenses

Production expenses decreased from $14.7 million in the third quarter of 2014 to $12.6 million in the third quarter of 2015. On a per unit basis, production expenses decreased $1.11 per Boe to $8.62 per Boe in the third quarter of 2015 compared to the third quarter of 2014. The lower cost on a per unit basis in 2015 is primarily due to lower contract labor and maintenance costs.

Production Taxes

We pay production taxes based on realized crude oil and natural gas sales. These costs were $5.0 million in the third quarter of 2015 compared to $12.1 million in the third quarter of 2014. The $7.1 million decrease in production taxes in 2015 compared to 2014 was due to the decline in oil, natural gas and NGL sales, excluding the effect of settled derivatives. As a percentage of oil and natural gas sales, our production taxes were flat at 10.1% in the third quarter of both 2015 and 2014. Certain of our production is in Montana and North Dakota jurisdictions that have lower initial tax rates for an established period of time or until an established threshold of production is exceeded, after which the tax rates are increased to the standard tax rate.

General and Administrative Expense

General and administrative expense was $4.6 million for the third quarter of 2015 compared to $4.7 million for the third quarter of 2014. The lower year-over-year expenses in 2015 as compared to 2014 resulted from lower travel costs of $0.1 million, office and other expenses of $0.1 million and legal and professional expenses of $0.7 million, primarily due to a legal settlement of $0.6 million that occurred in 2014. These cost reductions were partially offset by increased compensation expenses of $0.3 million and one-time restructuring costs of $0.5 million. In September 2015, we restructured certain of our operations in response to the current oil and gas commodity environment, which included a reduction in workforce.

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Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion ("DD&A") was $31.7 million in the third quarter of 2015 compared to $45.6 million in the third quarter of 2014. Depletion expense, the largest component of DD&A, was $21.61 per Boe in the third quarter of 2015 compared to $30.02 per Boe in the third quarter of 2014. The aggregate decrease in depletion expense for the third quarter of 2015, compared to the third quarter of 2014 was driven by a 28% decrease in the depletion rate per Boe as well as a 4% production decrease in 2015 as compared to 2014. The 2015 depletion rate per BOE was lower due to the impairment of oil and gas properties which lowered the depletable base. Depreciation, amortization and accretion was $0.2 million in the third quarter of 2015 and 2014, respectively. The following table summarizes DD&A expense per Boe for the third quarters of 2015 and 2014:

	Three Months Ended September 30,			
	2015	2014	Change	Change
Depletion	$21.61	$30.02	$(8.41)	(28)%
Depreciation, Amortization and Accretion	0.11	0.15	(0.04)	(27)
Total DD&A Expense	$21.72	$30.17	$(8.45)	(28)%

Impairment of Oil and Natural Gas Properties

As a result of currently prevailing low commodity prices and their effect on the proved reserve values of properties in 2015, we recorded a non-cash ceiling test impairment of $354.4 million in the third quarter of 2015. The Company did not have any impairment of its proved oil and gas properties in the third quarter of 2014. The impairment charge affected our reported net income but did not reduce our cash flow.

If commodity prices remain at decreased levels, the trailing 12-month average price used in the ceiling calculation will decline and will likely cause additional future write downs of our oil and natural gas properties. Continued write downs of oil and natural gas properties are expected to occur until such time as commodity prices have stabilized or recovered long enough to stabilize or increase the trailing 12-month average price used in the ceiling calculation. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Interest Expense

Interest expense, net of capitalized interest, was $16.2 million in the third quarter of 2015 compared to $10.6 million in the third quarter of 2014. The increase in interest expense was primarily due to our capital development program and working capital requirements, which increased borrowings between periods. Additionally, capitalized interest costs decreased by $0.8 million in the third quarter of 2015, as compared to the third quarter of 2014.

Income Tax Provision

The income tax benefit recognized during the third quarter of 2015 was $0.1 million or 0.0% of the loss before income taxes, as compared to an income tax provision of $35.1 million or 37.7% of income before income taxes in the third quarter of 2014. The lower effective tax rate in 2015 relates to the valuation allowance placed on the net deferred tax asset in the third quarter of 2015, in addition to state income taxes and estimated permanent differences.

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Results of Operations for the nine-month periods ended September 30, 2015 and September 30, 2014

The following table sets forth selected operating data for the periods indicated.

	Nine Months Ended September 30,		
	2015	2014	% Change
Net Production:			
Oil (Bbl)	3,904,823	3,683,701	6
Natural Gas and NGLs (Mcf)	3,559,561	2,558,355	39
Total (Boe)	4,498,083	4,110,094	9
Net Sales:			
Oil Sales	$157,331,893	$319,648,167	(51)
Natural Gas and NGL Sales	5,966,491	17,501,443	(66)
Gain on Derivative Instruments, Net	54,818,997	349,335	15,592
Other Revenue	27,004	5,863	361
Total Revenues	218,144,385	337,504,808	(35)
Average Sales Prices:			
Oil (per Bbl)	$40.29	$86.77	(54)
Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl)	29.18	(6.81)	(528)
Oil Net of Settled Derivatives (per Bbl)	69.47	79.96	(13)
Natural Gas and NGLs (per Mcf)	1.68	6.84	(75)
Realized Price on a Boe Basis Including all Realized Derivative Settlements	61.63	75.93	(19)
Operating Expenses:			
Production Expenses	$40,331,314	$39,428,008	2
Production Taxes	17,333,123	34,073,083	(49)
General and Administrative Expense	13,224,012	12,677,481	4
Depletion, Depreciation, Amortization and Accretion	113,629,323	123,959,402	(8)
Impairment of Oil and Natural Gas Properties	996,815,713	-	-
Costs and Expenses (per Boe):			
Production Expenses	$8.97	$9.59	(6)
Production Taxes	3.85	8.29	(54)
General and Administrative Expense	2.94	3.08	(5)
Depletion, Depreciation, Amortization and Accretion	25.26	30.16	(16)
Impairment of Oil and Natural Gas Properties	221.61	-	-
Net Producing Wells at Period End	201.9	177.5	14

Oil and Natural Gas Sales

In the first nine months of 2015, our oil, natural gas and NGL sales, excluding the effect of settled derivatives, decreased 52% as compared to the first nine months of 2014, driven by a 56% decrease in realized prices, excluding the effect of settled derivatives, and partially offset by a 9% increase in production. The lower average realized price in the first nine months of 2015 as compared to the same period in 2014 was principally driven by lower average NYMEX oil and gas prices, which were partially offset by a lower oil price differential. Oil price differential during the first nine months of 2015 was $10.72 per barrel, as compared to $12.85 per barrel in the first nine months of 2014.

As discussed above, we add production through drilling success as we place new wells into production and through additions from acquisitions, while we lose production due to the natural decline of oil and natural gas produced from existing wells. In light of the low price commodity price environment, our annual capital expenditure budget declined over 70% in 2015 as compared to 2014. Despite the reduction in capital spending, our year-over-year production growth for the first nine months of 2015 was 9%. This year-over-year production growth was driven by the completion of a larger well-in-process inventory at the beginning of 2015, as well as improved recoveries on the 24.4 net wells added to production over the last twelve months.

Derivative Instruments

We enter into derivative instruments to manage the price risk attributable to future oil production. Gain on derivative instruments, net was a gain of $54.8 million in the first nine months of 2015, compared to a gain of $0.3 million in the first nine months of 2014. Gain (loss) on derivative instruments, net is comprised of (i) cash gains and losses we recognize on settled derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on derivative instruments outstanding at period-end.

For the first nine months of 2015, we incurred a gain on settled derivatives of $113.9 million, compared to a $25.1 million loss for the first nine months of 2014. Our average realized price (including all cash derivative settlements) received during the first nine months of 2015 was $61.63 per Boe compared to $75.93 per Boe in the first nine months of 2014. The gain (loss) on settled derivatives increased our average realized price per Boe by $25.33 in the first nine months of 2015 and decreased our average realized price per Boe by $6.10 in the first nine months of 2014.

As a result of forward oil price changes, we recognized a non-cash mark-to-market derivative loss of $59.1 million in the first nine months of 2015 compared to a $25.4 million gain in the first nine months of 2014. At September 30, 2015, all of our derivative contracts were recorded at their fair value, which was a net asset of $94.2 million, an increase of $86.7 million from the $7.5 million net asset recorded as of September 30, 2014.

Production Expenses

Production expenses were $40.3 million in the first nine months of 2015 compared to $39.4 million in the first nine months of 2014. We experience increases in operating expenses as we add new wells and maintain production from existing properties. On a per unit basis, production expenses decreased from $9.59 per Boe in the first nine months of 2014 to $8.97 per Boe in the first nine months of 2015. The lower cost on a per unit basis in 2015 is primarily due to lower repair and workover expenses, and a larger production base in 2015 over which the fixed cost components are spread.

Production Taxes

We pay production taxes based on realized crude oil and natural gas sales. These costs were $17.3 million in the first nine months of 2015 compared to $34.1 million in the first nine months of 2014. The $16.8 million decrease in production taxes in 2015 compared to 2014 was due to the decline in oil, natural gas and NGL sales, excluding the effect of settled derivatives. As a percentage of oil and natural gas sales, our production taxes were 10.6% and 10.1% in the first nine months of 2015 and 2014, respectively. This increase in production tax rates as a percentage of oil and gas sales in the first nine months of 2015 is due to a declining portion of our production that qualifies for lower initial tax rates. Certain of our production is in Montana and North Dakota jurisdictions that have lower initial tax rates for an established period of time or until an established threshold of production is exceeded, after which the tax rates are increased to the standard tax rate.

General and Administrative Expense

General and administrative expense was $13.2 million for the first nine months of 2015 compared to $12.7 million for the first nine months of 2014. General and administrative expenses in the first nine months of 2015 as compared to the first nine months of 2014 included higher compensation related expenses of $1.8 million and $0.5 million in restructuring costs. In September 2015, we restructured certain of our operations in response to the current oil and gas commodity environment, which included a reduction in work force. These higher amounts were partially offset by lower travel expenses of $0.3 million, insurance costs of $0.4 million and legal and professional expenses of $0.9

million, which included a legal settlement of $0.6 million in the 2014 period.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion (“DD&A”) was $113.6 million in the first nine months of 2015 compared to $124.0 million in the first nine months of 2014. Depletion expense, the largest component of DD&A, was $25.15 per Boe in the first nine months of 2015 compared to $30.02 per Boe in the first nine months of 2014. The aggregate decrease in depletion expense for the first nine months of 2015 compared to the first nine months of 2014 was driven by a 16% decrease in the depletion rate per Boe that was partially offset by a 9% increase in production. The 2015 depletion rate per BOE was lower due to the impairment of oil and gas properties which lowered the depletable base. Depreciation, amortization and accretion was $0.5 million in the first nine months of 2015 compared to $0.6 million in the first nine months of 2014. The following table summarizes DD&A expense per Boe for the first nine months of 2015 and 2014:

	Nine Months Ended September 30,			
	2015	2014	Change	Change
Depletion	$25.15	$30.02	$(4.87)	(16)%
Depreciation, Amortization and Accretion	0.11	0.14	(0.03)	(21)
Total DD&A Expense	$25.26	$30.16	$(4.90)	(16)%

Impairment of Oil and Natural Gas Properties

As a result of currently prevailing low commodity prices and their effect on the proved reserve values of properties in 2015, we recorded a non-cash ceiling test impairment of $996.8 million for the first nine months of 2015. The Company did not have any impairment of its proved oil and gas properties for the first nine months of 2014. The impairment charge affected our reported net income but did not reduce our cash flow.

If commodity prices remain at decreased levels, the trailing 12-month average price used in the ceiling calculation will decline and will likely cause additional future write downs of our oil and natural gas properties. Continued write downs of oil and natural gas properties are expected to occur until such time as commodity prices have stabilized or recovered long enough to stabilize or increase the trailing 12-month average price used in the ceiling calculation. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Interest Expense

Interest expense, net of capitalized interest, was $42.3 million for the first nine months of 2015 compared to $30.9 million in the first nine months of 2014. The increase in interest expense was primarily due to our capital development program and working capital requirements, which increased borrowings that were funded by our Revolving Credit Facility and the issuance of $200 million in principal amount of 2015 Mirror Notes. Additionally, capitalized interest costs decreased by $2.2 million in the first nine months of 2015, as compared to the first nine months of 2014.

Income Tax Provision

The income tax benefit recognized during the first nine months of 2015 was $202.4 million or 20.1% of the loss before income taxes, as compared to an income tax expense of $36.4 million or 37.7% in the first nine months of

2014. The lower effective tax rate in 2015 relates to the valuation allowance placed on the net deferred tax asset in the first nine months of 2015, in addition to state income taxes and estimated permanent differences.

Liquidity and Capital Resources

Overview

Our main sources of liquidity and capital resources as of the date of this report have been internally generated cash flow from operations, proceeds from senior unsecured notes, credit facility borrowings and cash settlements of derivative contracts. Our primary uses of capital have been for the acquisition and development of our oil and gas properties. We continually monitor potential capital sources in order to enhance liquidity and decrease leverage.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity derivative contracts. Oil accounted for 88% and 90% of our total production volumes in the first nine months of 2015 and 2014, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas and NGL prices. As of October 1, 2015, we had derivative contracts covering the sale of approximately 75% of our forecasted oil production volumes for the remainder of 2015. For a list of all of our outstanding derivatives as of October 1, 2015, see Note 11 in the Notes to Condensed Financial Statements.

Our amended and restated credit agreement governing our revolving credit facility (the “Revolving Credit Facility”) has a maximum facility size of $750 million, subject to a semi-annual borrowing base redetermination in April and October of each year. In October 2015, our semi-annual borrowing base redetermination was completed and reaffirmed at $550 million. At September 30, 2015, we had $170 million of borrowings on the Revolving Credit Facility with $380 million of borrowing availability based on the October 2015 borrowing base redetermination. Additionally, we have $700 million aggregate principal amount of outstanding 8.000% senior unsecured notes due June 1, 2020 (the “Notes”).

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

At September 30, 2015, we had $867.7 million of total debt outstanding, $28.3 million of stockholders’ (deficit), and $7.1 million of cash on hand. Additionally, at September 30, 2015, there was $380.0 million of borrowing availability under our Revolving Credit Facility. At December 31, 2014, we had $806.1 million of debt outstanding, $770.9 million of stockholders’ equity and $9.3 million of cash on hand.

Price for oil declined significantly in the fourth quarter of 2014 and into 2015, which has substantially decreased our cash flows from operating activities. We partially mitigate the price of crude oil by entering into hedging arrangements with respect to a portion of our expected oil production. At September 30, 2015, we had open oil derivative contracts for 990,000 Bbls in 2015 and 1,800,000 Bbls in 2016 at an average fixed price per Bbl of $89.82 and $77.50, respectively. Sustained low oil prices could require us to incur additional indebtedness to fund planned capital expenditures and other operations. Continued low oil and natural gas prices, or further declines in such prices, could also adversely affect our ability to incur additional indebtedness or access the capital markets on favorable terms, or at all.

In response to the sharp pricing declines experienced in the fourth quarter of 2014 and into 2015, we established a 2015 capital expenditures budget of approximately $140 million, representing a 74% reduction from our actual capital expenditures in 2014. Our recent capital commitments have been to fund drilling in the Williston Basin and, to a lesser extent, fund acreage acquisitions. Our strategy is to continue to (1) increase cash flow generated from operations by new drilling and completion activities, subject to economic and industry conditions and (2) pursue acquisition and disposition opportunities. We expect to fund our near term capital requirements and working capital needs with cash flows from operations and available borrowing capacity under our Revolving Credit Facility. Our capital expenditures could be further curtailed if our cash flows decline from expected levels. Because production from existing oil and natural gas wells declines over time, further reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future.

Working Capital

Our working capital balance fluctuates as a result of changes in commodity pricing and production volumes, collection of receivables, expenditures related to our development and production operations and the impact of our outstanding derivative instruments. Absent any significant effects from our commodity derivative instruments, we generally maintain low cash and cash equivalent balances because we use cash from operations to fund our development activities and reduce our bank debt.

At September 30, 2015, we had working capital surplus of $32.8 million compared to a deficit of $59.7 million at December 31, 2014. Current assets decreased by $36.8 million and current liabilities decreased by $129.3 million at September 30, 2015, compared to December 31, 2014. The decrease in current assets is primarily due to a $41.0 million decrease in the value of our derivative instruments at September 30, 2015, which is primarily due to the gains on settled derivatives recognized in the first nine months of 2015, as well as fluctuations in the market price of crude oil since the end of 2014. The change in current liabilities is primarily due to a decrease of $132.7 million in accounts payable and largely due to (i) a reduction in accrued capital expenditures in conjunction with a decrease in the number of drilling rigs operating on our properties, (ii) the payment of accrued 2014 bonuses and (iii) other changes due primarily to fluctuations in the timing and amount of the payment of expenditures related to exploration and production operations during the nine-month period ended September 30, 2015.

Cash Flows

Our cash flows for the nine-month periods ended September 30, 2015 and 2014 are presented in the following table and discussed below:

	Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Cash Flows Provided by Operating Activities	$174,821	$209,371
Cash Flows Used for Investing Activities	(233,224)	(345,350)
Cash Flows Provided by Financing Activities	56,108	138,341
Net (Decrease) Increase in Cash and Cash Equivalents	$(2,295)	$2,362

Cash Flows from Operating Activities

Our operating cash flow is primarily influenced by the prices we receive for our oil, natural gas and NGLs, the quantity of oil, natural gas and NGLs we sell and settlements of derivative contracts. Prices for oil declined significantly in the fourth quarter of 2014 and into 2015, which has decreased our cash flow from operations. The decline in operating cash flows caused by lower oil prices has been partially offset by cash flow from our derivative settlements. Our cash flows from operating activities are also impacted by changes in working capital. The decrease in net cash provided by operating activities in 2015 over 2014 was primarily due to changes in working capital as a result of lower commodity price and reduced drilling activities in 2015.

Cash Flows from Investing Activities

We had cash flows used in investing activities of $233.2 million and $345.3 million during the nine-month periods ended September 30, 2015 and 2014, respectively, primarily as a result of our capital expenditures for drilling, development and acquisition costs. The decrease in cash used in investing activities for the first nine months of 2015 as compared to same period of 2014 was attributable to a decrease in oil and gas spending in light of the lower commodity price environment in 2015.

Our cash flows used in investing activities reflects actual cash spending, which can lag several months from when the related costs were incurred. As a result, our actual cash spending is not always reflective of current levels of development activity. For instance, during the nine-month period ended September 30, 2015, our capitalized costs incurred for oil and natural gas properties (e.g. drilling and completion costs and other capital expenditures) amounted to $105.4 million, while the actual cash spend in this regard amounted to $233.4 million. Our cash spend for development and acquisition activities for the nine months ended September 30, 2015 and 2014 are summarized in the following table:

	Nine Months Ended September 30,	
	2015	2014
	(in millions, unaudited)	
Drilling and Completion Costs	$226.6	$302.2
Acreage and Related Activities	5.2	39.3
Other Capital Expenditures	1.6	3.8
Total	$233.4	$345.3

Development and acquisition activities are highly discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and returns.

Cash Flows from Financing Activities

Our financing activities provided $56.1 million of cash for the nine-month period ended September 30, 2015, compared to $138.3 million used in the same period in 2014. The change is due primarily to a $200 million Notes issuance in May 2015, which was partially offset by $5.7 million in debt issuance costs and net repayments of $128.0 million under the Revolving Credit Facility during the nine-month period ended September 30, 2015. During the nine-month period ended September 30, 2014, Northern's cash flows from financing activities was primarily due to net borrowing under the Revolving Credit Facility.

Revolving Credit Facility

In February 2012, we entered into an amended and restated credit agreement providing for our Revolving Credit Facility, which replaced our previous revolving credit facility with a syndicated facility. Our bank group is comprised of a group of commercial banks, with no single bank holding more than 12% of the total facility. The Revolving Credit Facility, which is secured by substantially all of our assets, provides for a commitment equal to the lesser of the facility amount or the borrowing base. At September 30, 2015, we had $170 million of borrowings on the Revolving Credit Facility with $380 million of borrowing availability. In October 2015, our borrowing base was reaffirmed at $550 million.

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

0.50%. At September 30, 2015, the commitment fee was 0.375% and the interest rate margin was 1.75% on LIBOR loans and 0.75% on base rate loans.

The Revolving Credit Facility contains negative covenants that limit our ability, among other things, to pay any cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0, a ratio of secured debt to EBITDAX (as defined in the credit agreement) of no greater than 2.5 to 1.0 and a ratio of EBITDAX (as defined in the credit agreement) to interest expense (as defined in the credit agreement) of no less than 2.5 to 1.0. We were in compliance with our financial covenants under the Revolving Credit Facility at September 30, 2015.

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

8.000% Senior Notes due 2020

On May 18, 2012, we issued at par value $300 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the “Original Notes”). On May 13, 2013, we issued at a price of 105.25% or par an additional $200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the “2013 Follow-on Notes”). On May 18, 2015, the Company issued at a price of 95.000% of par an additional $200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the “2015 Mirror Notes” and, together with the Original Notes and the 2013 Follow-on Notes, the “Notes”). Interest is payable on the Notes semi-annually in arrears on each June 1 and December 1. The issuance of the Original Notes resulted in net proceeds to us of approximately $291.2 million, the issuance of the 2013 Follow-on Notes resulted in net proceeds to us of approximately $200.1 million, and the issuance of the 2015 Mirror Notes resulted in net proceeds to us of approximately $185.0 million. Collectively, the net proceeds are in use to fund our exploration, development and acquisition program and for general corporate purposes (including repayment of borrowings that were outstanding under the Revolving Credit Facility at the time the Notes were issued).

Prior to June 1, 2016, we may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after June 1, 2016, we may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104% for the twelve-month period beginning on June 1, 2016, 102% for the twelve-month period beginning June 1, 2017 and 100% beginning on June 1, 2018, plus accrued and unpaid interest to the redemption date.

The Original Notes and the 2013 Follow-on Notes are governed by an Indenture, dated as of May 18, 2012, by and among the Company and Wilmington Trust, National Association (the “Original Indenture”). The 2015 Mirror Notes are governed by an Indenture, dated as of May 18, 2015, by and among the Company and Wilmington Trust, National Association (the “Mirror Indenture”). The terms and conditions of the Mirror Indenture conform, in all material respects, to the terms and conditions set forth in the Original Indenture. As such, the Mirror Indenture, together with the Original Indenture, are referred to herein as the “Indenture”.

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

The Indenture contains customary events of default, including:

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

failure by us to comply with our other obligations under the Indenture, in certain cases subject to notice and grace periods;

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

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel. Oil and natural gas prices decreased significantly in the fourth quarter of 2014 and have remained depressed in 2015. The lower commodity pricing has reduced service costs in 2015. If service cost pricing remains at the current 2015 levels, we do not currently expect business costs to materially increase until higher prices for oil and natural gas create increased demand for materials, services and personnel.

Contractual Obligations and Commitments

Our material long-term debt obligations, capital lease obligations and operating lease obligations or purchase obligations as of December 31, 2014, are included in Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

Significant 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 2014 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, 2014.

Non-GAAP Financial Measures

We define Adjusted Net Income as net income excluding (i) (gain) loss on the mark-to-market of derivative instruments, net of tax, (ii) restructuring costs, net of tax, (iii) impairment of oil and natural gas properties, net of tax and (iv) certain legal settlements, net of tax. Our Adjusted Net Income for the third quarter of 2015 was $14.6 million (representing approximately $0.24 per diluted share), compared to $15.6 million (representing approximately $0.26 per diluted share) for the third quarter of 2014. For the third quarter of 2015, the decrease in non-GAAP Adjusted Net Income is primarily due to lower realized commodity prices as well as higher interest expense, which were partially offset by lower depletion expense. Our Adjusted Net Income for the nine months ended September 30, 2015 was $32.1 million (representing approximately $0.53 per diluted share), compared to $44.7 million (representing approximately $0.74 per diluted share) for the nine months ended September 30, 2014. The decrease in non-GAAP Adjusted Net Income is primarily due to lower realized commodity prices as well as higher interest costs, which were partially offset by our continued addition of crude oil and natural gas production from new wells in 2015 compared to 2014 and lower depletion expense.

We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization, and accretion, (iv) (gain) loss on the mark-to-market of derivative instruments, (v) non-cash share based compensation expense and (vi) impairment of oil and natural gas properties. Adjusted EBITDA for the third quarter of 2015 was $71.7 million, compared to Adjusted EBITDA of $81.4 million for the third quarter of 2014. The decrease in Adjusted EBITDA is primarily due to lower realized commodity prices. Adjusted EBITDA for the nine months ended September 30, 2015 was $209.6 million, compared to Adjusted EBITDA of $228.0 million for the nine months ended September 30, 2014. The decrease in Adjusted EBITDA is primarily due to lower realized commodity prices, which were partially offset by our continued addition of crude oil and natural gas production from our wells in 2015 compared to 2014.

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

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

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

Reconciliation of Adjusted Net Income

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Net (Loss) Income	$(323,242,032)	$57,985,310	$(803,041,218)	$60,162,624
Add:				
Impact of Selected Items:				
(Gain) Loss on the Mark-to-Market of Derivative Instruments	(8,408,682)	(68,600,900)	59,115,913	(25,433,684)
Restructuring Costs	523,487	-	523,487	-
Impairment of Oil and Natural Gas Properties	354,422,654	-	996,815,713	-
Legal Settlements	-	577,000	-	577,000
Selected Items, Before Income Taxes (Benefit)	346,537,459	(68,023,900)	1,056,455,113	(24,856,684)
Income Tax of Selected Items(1)	(8,710,160)	25,645,010	(221,312,923)	9,370,970
Selected Items, Net of Income Taxes (Benefit)	337,827,299	(42,378,890)	835,142,190	(15,485,714)
Adjusted Net Income	$14,585,267	$15,606,420	$32,100,972	$44,676,910
Weighted Average Shares Outstanding – Basic	60,679,257	60,559,827	60,627,142	60,753,752
Weighted Average Shares Outstanding – Diluted	60,725,886	60,736,502	60,716,819	60,950,641
Net (Loss) Income Per Common Share – Basic	$(5.33)	$0.96	$(13.25)	$0. 99
Add:				
Impact of Selected Items, Net of Income Taxes	5.57	(0.70)	13.78	(0.25)
Adjusted Net Income Per Common Share – Basic	$0.24	$0.26	$0.53	$0.74
Net (Loss) Income Per Common Share – Diluted	$(5.32)	$0.95	$(13.23)	$0.99
Add:				
Impact of Selected Items, Net of Income Taxes	5.56	(0.69)	13.76	(0.25)
Adjusted Net Income Per Common Share – Diluted	$0.24	$0.26	$0.53	$0.74

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(1) For the 2015 columns, this represents tax impact using an estimated tax rate of 37.2% and 37.0% for the three and nine months ended September 30, 2015, respectively. These columns include a $120.1 million and $170.0 million adjustment for a change in valuation allowance for the three and nine months ended September 30, 2015, respectively. For the 2014 columns, this represents tax impact using an estimated tax rate of 37.7%.

Reconciliation of Adjusted EBITDA

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Net (Loss) Income	$(323,242,032)	$57,985,310	$(803,041,218)	$60,162,624
Add:				
Interest Expense	16,154,160	10,624,246	42,278,400	30,850,004
Income Tax Provision (Benefit)	(77,544)	35,050,000	(202,424,154)	36,400,000

Depreciation, Depletion, Amortization and Accretion	31,670,479	45,646,232	113,629,323	123,959,402
Impairment of Oil and Natural Gas Properties	354,422,654	-	996,815,713	-
Non-Cash Share Based Compensation	1,141,241	736,971	3,221,715	2,022,180
(Gain) Loss on the Mark-to-Market of Derivative Instruments	(8,408,682)	(68,600,900)	59,115,913	(25,433,684)
Adjusted EBITDA	$71,660,276	$81,441,859	$209,595,692	$227,960,526

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, 2014 and, except as set forth below, have not materially changed since that report was filed.

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and other factors. Historically, the markets for oil and natural gas have been volatile, and our management believes these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue during 2015 and 2014 generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices.

We enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil price volatility. All derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses are recorded to gain (loss) on settled derivatives and mark-to-market gains or losses are recorded to gains (losses) on the mark-to-market of derivative instruments on the statements of operations rather than as a component of other comprehensive income or other income (expense).

We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under our Revolving Credit Facility. As of September 30, 2015, we had entered into derivative agreements covering 1.0 million barrels for the remainder of 2015 and 1.8 million barrels for 2016.

The following table reflects open commodity swap contracts as of September 30, 2015, the associated volumes and the corresponding fixed price.

Settlement Period	Oil (Barrels)	Fixed Price ($)
Swaps-Crude Oil		
10/01/15 – 12/31/15	180,000	89.00
10/01/15 – 12/31/15	90,000	89.00
10/01/15 – 12/31/15	90,000	89.02
10/01/15 – 12/31/15	45,000	89.00
10/01/15 – 12/31/15	45,000	89.00
10/01/15 – 12/31/15(1)	90,000	90.75
10/01/15 – 12/31/15(1)	90,000	91.00
10/01/15 – 12/31/15(1)	90,000	91.25
10/01/15 – 06/30/16	270,000	89.00
10/01/15 – 06/30/16	270,000	90.00
10/01/15 – 06/30/16	270,000	91.00
01/01/16 – 06/30/16	180,000	90.00

01/01/16 – 06/30/16	90,000	90.00
01/01/16 – 06/30/16	90,000	90.00
07/01/16 – 12/31/16	180,000	65.00
07/01/16 – 12/31/16	180,000	64.93
07/01/16 – 12/31/16	90,000	65.00
07/01/16 – 12/31/16	180,000	65.00
07/01/16 – 12/31/16	180,000	64.93
07/01/16 – 12/31/16	90,000	65.30

(1) The Company has entered into crude oil derivative contracts that give counterparties the option to extend certain current derivative contracts for an additional six-month period. Options covering a notional volume of 90,000 barrels per month are exercisable on or about December 31, 2015. If the counterparties exercise all such options, the notional volume of our existing crude oil derivative contracts will increase by 90,000 barrels per month at an average price of $91.00 per barrel for each month during the period January 1, 2016 through June 30, 2016.

As of September 30, 2015, we had a total volume on open commodity swaps of 2.8 million barrels at a weighted average price of approximately $81.87 per barrel.

The following table reflects the weighted average price of open commodity swap derivative contracts as of September 30, 2015, by year with associated volumes.

Weighted Average Price
Of Open Commodity Swap Contracts

Year	Volumes (Bbl)	Weighted Average Price ($)
2015	990,000	89.82
2016	1,800,000	77.50

Interest Rate Risk

Our long-term debt is comprised of borrowings that contain fixed and floating interest rates. The Notes bear interest at an annual fixed rate of 8% and our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement. During the nine-month period ended September 30, 2015, we had $271.4 million in average outstanding borrowings under our Revolving Credit Facility at a weighted average rate of 2.1%. We have the option to designate the reference rate of interest for each specific borrowing under the Revolving Credit Facility as amounts are advanced. Borrowings based upon the London Interbank Offered Rate (“LIBOR”) will bear interest at a rate equal to LIBOR plus a spread ranging from 1.5% to 2.5% depending on the percentage of borrowing base that is currently advanced. Any borrowings not designated as being based upon LIBOR will bear interest at a rate equal to the current prime rate published by the Wall Street Journal, plus a spread ranging from 0.5% to 1.5%, depending on the percentage of borrowing base that is currently advanced. We have the option to designate either pricing mechanism. Interest payments are due under the Revolving Credit Facility in arrears, in the case of a loan based on LIBOR on the last day of the specified interest period and in the case of all other loans on the last day of each March, June, September and December. All outstanding principal is due and payable upon termination of the Revolving Credit Facility.

Our Revolving Credit Facility allows us to fix the interest rate of borrowings under it for all or a portion of the principal balance for a period up to three months; however our borrowings are generally withdrawn with interest rates fixed for one month. Thereafter, to the extent we do not repay the principle, our borrowings are rolled over and the interest rate is reset based on the current LIBOR or prime rate as applicable. As a result, changes in interest rates can impact results of operations and cash flows.

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

As of September 30, 2015, 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 September 30, 2015.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended September 30, 2015, that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

Our company is subject from time to time to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business.

Item 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 filed with the SEC for the period ended December 31, 2014.

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

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases made by or on behalf of the company, or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of our common stock during the quarter ended September 30, 2015.

Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publically Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs(2)
Month #1				
July 1, 2015 to July 31, 2015	980	$6.11	-	$ 108.3 million
Month #2				
August 1, 2015 to August 31, 2015	-	-	-	108.3 million
Month #3				
September 1, 2015 to September 30, 2015	1,288	5.21	-	108.3 million
Total	2,268	$5.60	-	$ 108.3 million

(1) All shares purchased reflect shares surrendered in satisfaction of tax obligations in connection with the vesting of restricted stock awards.

(2) In May 2011, our board of directors approved a stock repurchase program to acquire up to $150 million shares of our company's outstanding common stock. In total, we have repurchased 3,190,268 shares under this program through September 30, 2015 at a weighted average price of $13.06 per share.

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:	November 5, 2015	By:	/s/ Michael L. Reger Michael L. Reger, Chief Executive Officer and Director
Date:	November 5, 2015	By:	/s/ Thomas W. Stoelk Thomas W. Stoelk, Chief Financial Officer

EXHIBIT INDEX

Unless otherwise indicated, all documents incorporated by reference to a document filed with the SEC pursuant to the Exchange Act, are located under SEC file number 001-33999.

Exhibit No.	Description	Reference
3.1	Articles of Incorporation of Northern Oil and Gas, Inc. dated June 28, 2010	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 2, 2010
3.2	By-Laws of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on July 2, 2010
4.1	Specimen Stock Certificate of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 29, 2012
4.2	Indenture, dated May 18, 2012, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.000% Senior Note due 2020)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2012
4.3	Indenture, dated May 18, 2015, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.000% Senior Note due 2020)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2015
4.4	Registration Rights Agreement, dated May 18, 2015, between Northern Oil and Gas, Inc. and RBC Capital Markets, LLC, as representative of the Initial Purchasers, identified therein	Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2015
10.1	Seventh Amendment to the Third Amended and Restated Credit Agreement, dated October 21, 2015, by and among Northern Oil and Gas, Inc., Royal Bank of Canada, and the Lenders party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 22, 2015
10.2*	Amended and Restated Employment Agreement by and between Michael Reger and Northern Oil and Gas, Inc., dated October 7, 2015	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 9, 2015
10.3*	Performance-Based Restricted Stock Award Agreement, dated October 7, 2015, between Northern Oil and Gas, Inc. and Michael Reger	Incorporated by reference to Exhibit 99.2 to the Schedule 13D filed with the SEC by Mr. Reger with respect to the Registrant on October 16, 2015 (file no. 005-82844)
12.1	Calculation of Ratio of Earnings to Fixed Charges	Filed herewith
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted	Filed herewith

	pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
101.INS	XBRL Instance Document	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema Document	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith

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