NORTHERN OIL & GAS, INC.
Form 10-Q
August 05, 2016
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2016

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

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

(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 ¨	Accelerated Filer x
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 August 1, 2016, there were 64,595,119 shares of our common stock, par value $0.001, outstanding.

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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.

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"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.

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(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 twelve-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.” Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

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NORTHERN OIL AND GAS, INC.
FORM 10-Q

June 30, 2016

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PART I - FINANCIAL INFORMATION
Item 1. Condensed Financial Statements.
NORTHERN OIL AND GAS, INC.
CONDENSED BALANCE SHEETS
JUNE 30, 2016 AND DECEMBER 31, 2015

	June 30, 2016 (unaudited)	December 31, 2015
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$3,667,114	$3,390,389
Trade Receivables, Net	40,558,636	51,445,026
Advances to Operators	606,158	1,689,879
Prepaid and Other Expenses	1,251,051	892,867
Derivative Instruments	13,509,731	64,611,558
Total Current Assets	59,592,690	122,029,719
Property and Equipment:		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	2,377,267,538	2,336,757,089
Unproved	4,087,435	10,007,529
Other Property and Equipment	1,812,834	1,837,469
Total Property and Equipment	2,383,167,807	2,348,602,087
Less – Accumulated Depreciation, Depletion and Impairment	(1,986,276,814)	(1,759,281,704)
Total Property and Equipment, Net	396,890,993	589,320,383
Deferred Income Taxes (Note 9)	—	—
Other Noncurrent Assets, Net	8,900,536	10,080,846
Total Assets	$465,384,219	$721,430,948
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current Liabilities:		
Accounts Payable	$59,318,247	$65,319,170
Accrued Expenses	4,723,180	7,893,975
Accrued Interest	4,668,189	4,713,232
Derivative Instruments	1,387,889	—
Asset Retirement Obligations	252,222	188,770
Total Current Liabilities	70,349,727	78,115,147
Long-term Debt, Net	818,952,295	835,290,329
Asset Retirement Obligations	5,879,438	5,627,586
Total Liabilities	$895,181,460	$919,033,062
Commitments and Contingencies (Note 8)		
STOCKHOLDERS' DEFICIT		
Preferred Stock, Par Value $.001; 5,000,000 Authorized, No Shares Outstanding	—	—
Common Stock, Par Value $.001; 142,500,000 Authorized (6/30/2016 – 64,596,955	64,597	63,120

Shares Outstanding and 12/31/2015 – 63,120,384 Shares Outstanding)		
Additional Paid-In Capital	443,568,830	440,221,018
Retained Deficit	(873,430,668)	(637,886,252)
Total Stockholders’ Deficit	(429,797,241)	(197,602,114)
TOTAL LIABILITIES AND STOCKHOLDERS’ DEFICIT	$465,384,219	$721,430,948

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

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NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF OPERATIONS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2016 AND 2015
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
REVENUES				
Oil and Gas Sales	$42,527,847	$63,064,333	$70,895,188	$113,518,481
Gain (Loss) on Derivative Instruments, Net	(10,522,948)	(22,211,048)	(7,059,066)	3,452,235
Other Revenue	9,327	9,909	14,339	17,117
Total Revenues	32,014,226	40,863,194	63,850,461	116,987,833
OPERATING EXPENSES				
Production Expenses	11,081,973	13,564,801	23,041,232	27,763,891
Production Taxes	4,220,712	6,871,788	6,987,612	12,284,896
General and Administrative Expense	4,586,275	4,256,436	8,923,677	8,609,242
Depletion, Depreciation, Amortization and Accretion	16,176,863	36,745,805	34,022,952	81,958,844
Impairment of Oil and Natural Gas Properties	88,880,921	281,964,097	193,192,043	642,393,059
Total Expenses	124,946,744	343,402,927	266,167,516	773,009,932
LOSS FROM OPERATIONS	(92,932,518)	(302,539,733)	(202,317,055)	(656,022,099)
OTHER INCOME (EXPENSE)				
Interest Expense, Net of Capitalization	(16,046,325)	(14,387,693)	(32,145,007)	(26,124,240)
Write-off of Debt Issuance Costs	—	—	(1,089,507)	—
Other Income (Expense)	181	199	7,154	542
Total Other Income (Expense)	(16,046,144)	(14,387,494)	(33,227,360)	(26,123,698)
LOSS BEFORE INCOME TAXES	(108,978,662)	(316,927,227)	(235,544,415)	(682,145,797)
INCOME TAX BENEFIT	—	(66,866,610)	—	(202,346,610)
NET LOSS	$(108,978,662)	$(250,060,617)	$(235,544,415)	$(479,799,187)
Net Loss Per Common Share – Basic	$(1.78)	$(4.12)	$(3.86)	$(7.92)
Net Loss Per Common Share – Diluted	$(1.78)	$(4.12)	$(3.86)	$(7.92)
Weighted Average Shares Outstanding – Basic	61,180,313	60,644,635	61,071,948	60,600,652
Weighted Average Shares Outstanding – Diluted	61,180,313	60,644,635	61,071,948	60,600,652

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

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NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF CASH FLOWS
FOR THE SIX MONTHS ENDED JUNE 30, 2016 AND 2015
(UNAUDITED)

	Six Months Ended June 30, 2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Loss	$(235,544,415)	$(479,799,187)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities:		
Depletion, Depreciation, Amortization and Accretion	34,022,952	81,958,844
Amortization of Debt Issuance Costs	1,936,054	1,654,423
Write-off of Debt Issuance Costs	1,089,507	—
Amortization/Accretion of 8% Senior Notes Premium/Discount	245,230	(504,362)
Deferred Income Taxes	—	(202,350,555)
Loss on the Mark-to-Market of Derivative Instruments	52,489,716	67,524,595
Amortization of Deferred Rent	—	(3,664)
Share-Based Compensation Expense	3,300,313	1,944,474
Impairment of Oil and Natural Gas Properties	193,192,043	642,393,059
Other	339,821	801,556
Changes in Working Capital and Other Items:		
Trade Receivables, Net	10,886,389	3,525,404
Prepaid Expenses and Other	(358,183)	(605,242)
Accounts Payable	(93,913)	(4,504,082)
Accrued Interest	(93,045)	1,287,652
Accrued Expenses	(2,868,557)	(1,564,086)
Asset Retirement Obligations	(20,974)	(59,864)
Net Cash Provided By Operating Activities	58,522,938	111,698,965
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of Oil and Natural Gas Properties and Development Capital Expenditures, Net	(38,431,810)	(188,311,747)
Proceeds from Sale of Oil, Natural Gas, and Other Properties	—	160,944
Purchases of Other Property and Equipment	—	(15,562)
Net Cash Used for Investing Activities	(38,431,810)	(188,166,365)
CASH FLOWS FROM FINANCING ACTIVITIES		
Advances on Revolving Credit Facility	26,000,000	110,000,000
Repayments on Revolving Credit Facility	(44,000,000)	(220,000,000)
Debt Issuance Costs Paid	(428,515)	(5,566,131)
Issuance of Senior Unsecured Notes	—	190,000,000
Repurchase of Common Stock – Tax Obligations	(1,385,888)	(191,927)
Net Cash (Used for) Provided by Financing Activities	(19,814,403)	74,241,942
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	276,725	(2,225,458)
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	3,390,389	9,337,512
CASH AND CASH EQUIVALENTS – END OF PERIOD	$3,667,114	$7,112,054

Supplemental Disclosure of Cash Flow Information		
Cash Paid During the Period for Interest	$30,186,285	$24,117,185
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	$53,613,405	$110,022,960
Capitalized Asset Retirement Obligations	$141,028	$306,386
Non-Cash Compensation Capitalized on Oil and Gas Properties	$792,804	$311,140

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

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NOTES TO CONDENSED FINANCIAL STATEMENTS
JUNE 30, 2016
(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 June 30, 2016, approximately 74% of Northern's 161,675 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, 2015, which has been derived from the Company's audited financial statements for the year ended December 31, 2015. 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, 2015, which were included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

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.

Reclassifications

Certain prior period balances in the condensed balance sheets have been reclassified to conform to the current year presentation. Such reclassifications had no impact on net income (loss), cash flows or stockholders' equity (deficit) previously reported.

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. Accounts receivable not expected to be collected within the next twelve months are included within Other Noncurrent Assets, Net on the condensed balance sheets.

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As of June 30, 2016 and December 31, 2015, the Company included accounts receivable of $6.8 million in Other Noncurrent Assets, Net due to their long-term nature.

The allowance for doubtful accounts at June 30, 2016 and December 31, 2015 was $4.9 million and $4.5 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 $52,507 and $75,450 for the three months ended June 30, 2016 and 2015, respectively. Depreciation expense was $105,160 and $155,226 for the six months ended June 30, 2016 and 2015, 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 six months ended June 30, 2016 and 2015, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Capitalized Certain Payroll and Other Internal Costs	$652,721	$555,260	$1,434,883	$980,688
Capitalized Interest Costs	78,680	220,930	209,604	958,681
Total	$731,401	$776,190	$1,644,487	$1,939,369

As of June 30, 2016, 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 six months ended June 30, 2016 and 2015 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 twelve-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

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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, the Company recorded non-cash ceiling test impairments for the three months ended June 30, 2016 and 2015 of $88.9 million and $282.0 million, respectively. The Company recorded non-cash ceiling test impairments for the six months ended June 30, 2016 and 2015 of $193.2 million and $642.4 million, respectively. The impairment charges 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 twelve-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 June 30, 2016 and 2015, the Company transferred into the full cost pool costs related to expired leases of $3.3 million and $3.4 million, respectively. For the six months ended June 30, 2016 and 2015, the Company transferred into the full cost pool costs related to expired leases of $5.3 million and $8.9 million, respectively.

Asset Retirement Obligations

The Company accounts for its abandonment and restoration liabilities under the Financial Accounting Standards Board ("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 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 June 30, 2016 and 2015 was $0.9 million and $0.9 million, respectively. The amortization of debt issuance costs for the six months ended June 30, 2016 and 2015 was $1.9 million and $1.7 million, respectively.

During the three and six months ended June 30, 2016, $0 and $1.1 million, respectively, of debt issuance costs were written-off as a result of a reduction in the borrowing base of the Revolving Credit Facility, which became effective in May 2016 and was due to the impact that lower commodity prices had on our oil and gas reserve valuation. There were no debt issuance costs written-off during the three and six months ended June 30, 2015.

As a result of the adoption of ASU No. 2015-03, “Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs” (“ASU 2015-03”), the Company reclassified unamortized debt issuance costs associated with its 8% Senior Notes, which totaled $12.5 million as of December 31, 2015, from "Debt Issuance Costs, Net" to a reduction of "Long-term Debt" on the balance sheets. Adoption of ASU 2015-03 had no impact on the Company's current and previously reported stockholders' equity (deficit), results of operations, or cash flows. Unamortized debt issuance costs associated with the Company's revolving credit facility, which amounted to $2.1 million and $3.3 million as of June 30, 2016 and December 31, 2015, respectively, were not reclassified and remain reflected in "Other Noncurrent Assets, Net" on the condensed balance sheets.

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Bond Premium/Discount on Senior Notes

On May 13, 2013, the Company recorded a bond premium of $10.5 million in connection with the 8.000% 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 and six months ended June 30, 2016 and 2015 was $0.4 million and $0.7 million in each period.

On May 18, 2015, the Company recorded a bond discount of $10.0 million in connection with the 8.000% 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 premium for the three months ended June 30, 2016 and 2015 was $0.5 million and $0.2 million, respectively. The amortization of the bond premium for the six months ended June 30, 2016 and 2015 was $1.0 million and $0.2 million, 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 three and six months ended June 30, 2016 and 2015, 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.

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.

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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 June 30, 2016, 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 June 30, 2016, 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 June 30, 2016 and December 31, 2015 was $318.5 million and $232.3 million, respectively.

Net Income (Loss) Per Common Share

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

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three and six months ended June 30, 2016 and 2015 are as follows:

	Three Months Ended June 30,	Six Months Ended June 30,

	2016	2015	2016	2015
Weighted Average Common Shares Outstanding – Basic	61,180,313	60,644,635	61,071,948	60,600,652
Plus: Potentially Dilutive Common Shares Including Stock Options and Restricted Stock	—	—	—	—
Weighted Average Common Shares Outstanding – Diluted	61,180,313	60,644,635	61,071,948	60,600,652
Restricted Stock and Stock Options Excluded From EPS Due To The Anti-Dilutive Effect	990,444	227,115	951,153	185,996

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 on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net on the condensed statements of operations. See Note 11 for a description of the derivative contracts into which the Company has entered.

New Accounting Pronouncements

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

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 is evaluating the impact of the future adoption of this standard on its condensed financial statements.

In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, which defers the effective date of ASU 2014-09 for all entities by one year. This update is effective for public business entities for annual reporting periods beginning after December 15, 2017, including interim periods within those reporting periods. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. The Company is evaluating the impact of the future adoption of this standard on its condensed financial statements.

In February 2016, the FASB issued ASU 2016-02, Leases, which introduces the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous guidance. The guidance will be effective for annual reporting periods beginning after December 15, 2018 and interim periods within those fiscal years with early adoption permitted. The Company is evaluating the impact of the future adoption of this standard on its condensed financial statements.

In March 2016, the FASB issued ASU 2016-09, Compensation – Stock Compensation: Improvements to Employee Share-Based Payment Accounting, which relates to the accounting for employee share-based payments. This standard addresses several aspects of the accounting for share-based payment award transactions, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. This standard will be effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The Company is evaluating the impact of the future adoption of this standard on its condensed 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 June 30, 2016 and December 31, 2015 were approximately $53.6 million and $59.5 million, respectively.

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Acquisitions

For the six months ended June 30, 2016, the Company acquired approximately 871 net acres, for an average cost of approximately $1,704 per net acre, in its key prospect areas in the form of effective leases.

For the six months ended June 30, 2015, the Company acquired approximately 2,205 net acres, for an average cost of approximately $1,325 per net acre, in its key prospect areas in the form of effective leases.

Unproved Properties

Unproved properties not subject to depletion comprise approximately 33,531 net acres and 38,003 net acres of undeveloped leasehold interests at June 30, 2016 and December 31, 2015, 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. 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 historically have not been subject to specified drilling projects. 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. For the six months ended June 30, 2016 and 2015, the Company included in the pool of cost subject to depletion $5.0 million and $31.3 million, respectively, for unproved property costs related to expiring leases.

NOTE 4 LONG-TERM DEBT

The Company's long-term debt consists of the following:

	June 30, 2016		
	Long-term Debt	Debt Issuance Costs, Net	Long-term Debt, Net
8% Senior Notes	$698,050,059	$(11,097,764)	$686,952,295
Revolving Credit Facility[1]	132,000,000	—	132,000,000
Total	$830,050,059	$(11,097,764)	$818,952,295

	December 31, 2015		
	Long-term Debt	Debt Issuance Costs, Net	Long-term Debt, Net
8% Senior Notes	$697,804,829	$(12,514,500)	$685,290,329

Revolving Credit Facility[1]	150,000,000	—	150,000,000
Total	$847,804,829	$(12,514,500)	$835,290,329

(1) Debt issuance costs related to our revolving credit facility are recorded in "Other Noncurrent Assets, Net" on the condensed balance sheets

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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 June 30, 2016, the facility amount was $750 million, the borrowing base was $350 million and there was a $132 million outstanding balance, leaving $218 million of borrowing capacity available under the facility.

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 unscheduled event-driven 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 1.0% to 2.0% or LIBOR borrowings at the Adjusted LIBOR Rate (as defined in the credit agreement) plus a spread ranging from 2.0% to 3.0%. 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 June 30, 2016, the commitment fee was 0.375% and the interest rate margin was 2.25% on LIBOR loans and 1.00% on base rate loans. At June 30, 2016, the Company had $132.0 million of LIBOR loans issued under the Revolving Credit Facility at a weighted average interest rate of 2.72%.

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, make investments, or maintain excess cash liquidity. 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 (through September 30, 2016). The minimum ratio of EBITDAX to interest expense that we are required to maintain begins stepping down with the quarter ending December 31, 2016, through the quarter ending March 31, 2018. The Company was in compliance with the financial covenants of the Revolving Credit Facility at June 30, 2016.

In May 2016, the Company's semi-annual borrowing base redetermination was completed, and the borrowing base was reduced by 36%, to $350 million, due to the impact that lower commodity prices have had on the valuation of the Company's proved reserves. In connection with the redetermination, the credit agreement governing the Revolving Credit Facility was amended to (i) reduce the minimum ratio of EBITDAX to interest expense that the Company is required to maintain (currently 2.5 to 1.0) beginning with the quarter ending December 31, 2016 and stepping down through the quarter ending March 31, 2018, (ii) increase the interest rate on borrowings by 50 basis points and (iii) limit the Company's ability to maintain excess cash liquidity without using it to reduce outstanding borrowings under the Revolving Credit Facility.
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).

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Prior to June 1, 2016, the Company could have redeemed 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 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 $25.0 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 $25.0 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

In May 2016, the Company's shareholders approved an amendment to the Company's Articles of Incorporation to increase the number of authorized shares of common stock by 50%, from 95,000,000 to 142,500,000. As a result, the Company's Amended and Restated Articles of Incorporation authorize the issuance of up to 147,500,000 shares. The shares are classified in two classes, consisting of 142,500,000 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.

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Common Stock

The following is a schedule of changes in the number of shares of common stock outstanding during the six months ended June 30, 2016 and the year ended December 31, 2015:

	Six Months Ended June 30, 2016	Year Ended December 31, 2015
Beginning Balance	63,120,384	61,066,712
Restricted Stock Grants (Note 6)	1,827,546	2,112,998
Other Surrenders	(339,524)	(57,929)
Other	(11,451)	(1,397)
Ending Balance	64,596,955	63,120,384

2016 Activity

During the six months ended June 30, 2016, 339,524 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 $1,315,000, which is 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 three and six months ended June 30, 2016 and June 30, 2015, the Company did not repurchase shares of its common stock under the stock repurchase program. 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.

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 2016, 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 1.6 million shares. As a result, as of June 30, 2016, there were 1,570,733 shares available for future awards under the 2013 Plan.

Restricted Stock Awards

During the six months ended June 30, 2016, the Company issued 1,827,546 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 March 2019. As of June 30, 2016, there was approximately $11.8 million of total unrecognized compensation expense related to unvested restricted stock that will be recognized over a weighted-average period of approximately 2.2 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.

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The following table reflects the outstanding restricted stock awards and activity related thereto for the six months ended June 30, 2016:

	Six Months Ended June 30, 2016	
	Number of Shares	Weighted-Average Price
Restricted Stock Awards:		
Restricted Shares Outstanding at Beginning of Period	2,365,396	$ 7.15
Shares Granted	1,827,546	4.04
Lapse of Restrictions	(776,613)	9.51
Shares Forfeited	(11,451)	10.04
Restricted Shares Outstanding at End of Period	3,404,878	$ 4.87

Stock Option Awards

On February 12, 2016, the board of directors granted options to purchase 250,000 shares of the Company's common stock under the Company's 2013 Plan. The Company granted options to purchase 250,000 shares of the Company's common stock to one of its board members in connection with his appointment as chairman of the board of directors in January 2016. These options were granted with an exercise price of $2.79 per share and were fully vested on the grant date. As a result of the options being fully vested on the grant date, the Company recorded share-based compensation expense of $0.4 million for the six months ended June 30, 2016.

	Stock Option Awards	Weighted-Average Exercise Price	Weighted Average Contractual Term
Outstanding as of December 31, 2015	141,872	$ 5.18	1.8
Granted	250,000	2.79	
Exercised	—	—	
Expired or canceled	—	—	
Forfeited	—	—	
Outstanding as of June 30, 2016[1]	391,872	$ 3.66	3.4

[1] All of the stock options outstanding were vested and exercisable at the end of the period.

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. The assumptions used to estimate the fair value of stock option awards granted are as follows:

	February 12, 2016
Risk-free interest rate	1.15 %
Expected term	5.0
Expected volatility	61.89 %
Fair value per option	$ 1.47

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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 2015 to 2016. 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 2016 base salaries in the form of awards expected to be settled in restricted shares of the Company's common stock that will vest over a three-year service-based period beginning in 2017.

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 actuals for the three months ended June 30, 2016 and a forecast period for the remaining nine months of 2016, a risk-free interest rate of 0.49% and 83.3% for Northern's stock price volatility.

The maximum value of the awards issuable if all participants earned the maximum award would total $2.8 million. For the three and six months ended June 30, 2016 and 2015, the Company recorded $0.1 million and $0.1 million, respectively, and $0.2 million and $0.1 million, respectively, of compensation expense in connection with these performance awards.

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. Until January 2, 2016, James Russell (J.R.) Reger was a 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 Chief Executive Officer, Michael Reger. As of June 30, 2016, the Company no longer considers Emerald a related party. At December 31, 2015, the Company's accounts receivable and accounts payable balances with Emerald were $1.1 million and $0.3 million, respectively. The Company recorded total revenues of $4.6 million from Emerald for the six months ended June 30, 2015.

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's interests in certain crude oil and natural gas leases from the State of North Dakota are subject to an ongoing dispute over the ownership of minerals underlying the bed of the Missouri River within the boundaries of the Fort Berthold Reservation. The ongoing dispute is between the State of North Dakota and three affiliated tribes, both of whom have purported to lease mineral rights in tracts of riverbed within the reservation boundaries. In the event the ongoing dispute results in a final judgment that is adverse to the Company's interests, the Company would be required to reverse approximately $6.8 million in revenue (net of accrued taxes) that has been accrued since the first quarter of 2013 based on the Company's purported interest in the crude oil and natural gas leases at issue. Due to the long-term nature of this title dispute, the $6.8 million in accounts receivable is included in “Other Noncurrent Assets, Net” on the condensed balance sheets. The Company fully maintains the validity of its interests in the crude oil and natural gas leases.

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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 June 30, 2016, a valuation allowance of $318.5 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 six months ended June 30, 2016 and 2015 consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Current Income Taxes (Benefit)	$—	$3,945	$—	$3,945
Deferred Income Taxes (Benefit)				
Federal	(36,912,000)	(102,925,000)	(78,749,000)	(229,750,000)
State	(3,903,000)	(13,853,000)	(7,532,000)	(22,508,000)
Valuation Allowance	40,815,000	49,907,445	86,281,000	49,907,445
Total Provision (Benefit)	$—	$(66,866,610)	$—	$(202,346,610)

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 six month periods ended June 30, 2016, 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 2016 relates to the valuation allowance placed on the net deferred tax assets in the second quarter of 2015, in addition to state income taxes and estimated permanent differences. The higher effective tax rate in 2015 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 six months ended June 30, 2016 and 2015, 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 June 30, 2016 and December 31, 2015 relating to unrecognized benefits.

The tax years 2015, 2014, 2013, 2012, 2011 and 2010 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.

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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 June 30, 2016 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)	$ —	$ 13,509,731	$ —
Commodity Derivatives – Current Liability (crude oil swaps)	—	(1,387,889)	—
Total	$ —	$ 12,121,842	$ —

	Fair Value Measurements at December 31, 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)	$ —	$ 64,611,558	$ —

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include crude oil swaps (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 June 30, 2016 is $819.0 million, which includes $687.0 million of senior unsecured notes including a net discount of $1.9 million and $132.0 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 $533.0 million at June 30, 2016. The Company's revolving credit facility approximates its fair value because of its floating rate structure.

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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 six months ended June 30, 2016 were approximately $0.1 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 six months ended June 30, 2016.

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Cash Received on Derivatives	$19,983,750	$30,982,180	$45,430,650	$70,976,830
Non-Cash Loss on Derivatives	(30,506,698)	(53,193,228)	(52,489,716)	(67,524,595)
Gain (Loss) on Derivative Instruments, Net	$(10,522,948)	$(22,211,048)	$(7,059,066)	$3,452,235

(1) Net cash receipts for crude oil collars for the three and six month periods ended June 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.

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The following table reflects open commodity swap contracts as of June 30, 2016, the associated volumes and the corresponding fixed price.

Settlement Period	Oil (Barrels)	Fixed Price ($)
Swaps-Crude Oil		
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
01/01/17 – 06/30/17	360,000	50.00
01/01/17 – 06/30/17	180,000	50.01
01/01/17 – 06/30/17	180,000	49.99

The following table reflects the weighted average price of open commodity swap derivative contracts as of June 30, 2016, by year with associated volumes.

Year	Volumes (Bbl)	Weighted Average Price ($)
2016	900,000	65.00
2017	720,000	50.00
2018 and beyond	—	—

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at June 30, 2016 and December 31, 2015, 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	June 30, 2016 Estimated Fair Value	December 31, 2015 Estimated Fair Value
Derivative Assets:			
Swap Contracts	Current Assets	$13,509,731	$64,611,558
Derivative Liabilities:			
Swap Contracts	Current Liabilities	$(1,387,889)	$—

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 June 30, 2016

	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	$13,509,731	$ —	$13,509,731
Offsetting of Derivative Liabilities:			
Current Liabilities	$(1,387,889)	$ —	$(1,387,889)

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	Estimated Fair Value at December 31, 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	$64,611,558	$ —	$64,611,558

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 June 30, 2016. 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 June 30, 2016 and December 31, 2015.

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 future events or outcomes. Items contemplating or making assumptions about actual or potential future sales, market size, collaborations, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond our Company's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following: 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. 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, 2015, 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. Forward-looking statements speak only as of the date they are made. 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

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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 2,705 gross (208.1 net) producing wells as of June 30, 2016.

Our average daily production in the second quarter of 2016 was approximately 13,933 Boe per day, of which approximately 86% was oil. In light of the low commodity price environment, our annual capital expenditure budget declined over 76% in 2015 as compared to 2014. Our year-over-year production decline in the second quarter was driven by the significant decline in development activities in North Dakota during 2016 and 2015. As of July 20, 2016, there were 31 active rigs operating in North Dakota, which is a 56% drop in the number of active rigs as compared to the same date in 2015. The reduction in rig count has lowered the number of new well additions and this lower activity level has not been able to offset the natural decline of our production base. In the twelve-month period ended June 30, 2016, we added 8.9 net wells to production, which compares to 34.0 net wells added in the twelve-month period ended June 30, 2015. This lower level of well completions caused production levels in the second quarter of 2016 to be approximately 16% lower than the same period a year ago. During the six months ended June 30, 2016, we participated in the drilling of 75 gross (3.8 net) wells that were completed and added to production.

As of June 30, 2016, we leased approximately 161,675 net acres, of which 100% were located in the Williston Basin of North Dakota and Montana. During the quarter ended June 30, 2016, we acquired approximately 107 net mineral acres at an average cost of approximately $5,210 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, net. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of oil. 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 market-to-market gains and losses we incur on derivative instruments outstanding at period end.

- 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.

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- 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 the supply 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 first six months of 2016 was $8.76 per barrel, as compared to $12.08 per barrel in the first six months of 2015. 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.

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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 substantially 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).

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 70 on July 20, 2015 to 31 on July 20, 2016. The decline in drilling activity and commodity prices has recently lowered drilling costs. During the second quarter of 2016, the weighted average authorization for expenditure (or AFE) cost for wells we elected to participate in was $6.9 million, compared to $7.7 million for the wells we elected to participate in during 2015.

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. 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 six months ended June 30, 2016 and 2015.

	Three Months Ended June 30,	
	2016	2015
Average NYMEX Prices[(a)]		
Natural Gas (per Mcf)	$2.25	$2.74
Oil (per Bbl)	$45.64	$57.95

	Six Months Ended June 30,	
	2016	2015
Average NYMEX Prices[(a)]		
Natural Gas (per Mcf)	$2.12	$2.77
Oil (per Bbl)	$39.78	$53.34

(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 has adversely affected our business and 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 June 30, 2016, the average WTI NYMEX pricing was $45.64 per Bbl or 21% lower than the average NYMEX price per Bbl for the comparable period in 2015. If the NYMEX prices remain at these depressed levels, our net revenue per Boe will decrease due to the lower average WTI NYMEX prices, as well as a reduced percentage of our oil production being hedged in 2016 as compared to 2015. At June 30, 2016, we have hedged 0.9 million barrels of oil at an average price of $65.00 per Bbl for the remainder of 2016 and 0.7 million barrels of oil at an average price of $50.00 per Bbl for the first six months of 2017. 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.

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Results of Operations for the Three-Month Periods Ended June 30, 2016 and June 30, 2015

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

	Three Months Ended June 30,		
	2016	2015	% Change
Net Production:			
Oil (Bbl)	1,087,710	1,314,490	(17)%
Natural Gas and NGLs (Mcf)	1,080,897	1,182,386	(9)%
Total (Boe)	1,267,860	1,511,554	(16)%
Net Sales:			
Oil Sales	$40,851,527	$61,060,912	(33)%
Natural Gas and NGL Sales	1,676,320	2,003,421	(16)%
Loss on Derivative Instruments, Net	(10,522,948)	(22,211,048)	(53)%
Other Revenue	9,327	9,909	(6)%
Total Revenues	32,014,226	40,863,194	(22)%
Average Sales Prices:			
Oil (per Bbl)	$37.56	$46.45	(19)%
Effect of Gain on Settled Derivatives on Average Price (per Bbl)	18.37	23.57	(22)%
Oil Net of Settled Derivatives (per Bbl)	55.93	70.02	(20)%
Natural Gas and NGLs (per Mcf)	1.55	1.69	(8)%
Realized Price on a Boe Basis Including all Realized Derivative Settlements	49.30	62.22	(21)%
Operating Expenses:			
Production Expenses	$11,081,973	$13,564,801	(18)%
Production Taxes	4,220,712	6,871,788	(39)%
General and Administrative Expense	4,586,275	4,256,436	8 %
Depletion, Depreciation, Amortization and Accretion	16,176,863	36,745,805	(56)%
Costs and Expenses (per Boe):			
Production Expenses	$8.74	$8.97	(3)%
Production Taxes	3.33	4.55	(27)%
General and Administrative Expense	3.62	2.82	28 %
Depletion, Depreciation, Amortization and Accretion	12.76	24.31	(48)%
Net Producing Wells at Period End	208.1	199.2	4 %

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Oil and Natural Gas Sales

In the second quarter of 2016, oil, natural gas and NGL sales, excluding the effect of settled derivatives, decreased 33% as compared to the second quarter of 2015, driven by a 20% decrease in realized prices, excluding the effect of settled derivatives, and a 16% decrease in production. The lower average realized price in the second quarter of 2016 as compared to the same period in 2015, was principally driven by lower average NYMEX oil prices, which was partially offset by a lower oil price differential. Oil price differential during the second quarter of 2016 was $8.08 per barrel, as compared to $11.50 per barrel in the second quarter of 2015.

We add production through drilling success as we place new wells into production and through additions from acquisitions, which is offset by the natural decline of our oil and natural gas sales from existing wells. In light of the low commodity price environment, we reduced our 2015 capital expenditure spending by 76% as compared to the prior year which lowered the number of new wells placed into production. In 2016, our capital expenditure budget was further reduced to provide a better matching of discretionary cash flow with our capital spending. Although the per well productivity improved, that was more than offset by the natural decline of oil and gas production in the second quarter of 2016 due to the lower number of new wells placed into production. In addition, certain of our operators began curtailing production beginning in 2016 due to their desire to produce the wells at higher prices than currently exist. Fewer new well additions coupled with production curtailments resulted in a production volume decrease of 16% when comparing the second quarter of 2016 to the second quarter of 2015.

Derivative Instruments

We enter into derivative instruments to manage the price risk attributable to future oil production. Our gain (loss) on derivative instruments, net was a loss of $10.5 million in the second quarter of 2016, compared to a loss of $22.2 million in the second quarter of 2015. 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 second quarter of 2016, we realized a gain on settled derivatives of $20.0 million, compared to a $31.0 million gain in the second quarter of 2015. Our average realized price (including all cash derivative settlements) in the second quarter of 2016 was $49.30 per Boe compared to $62.22 per Boe in the second quarter of 2015. The gain (loss) on settled derivatives increased our average realized price per Boe by $15.76 in the second quarter of 2016 and $20.50 in the second quarter of 2015.

Mark-to-market derivative gains and losses was a loss of $30.5 million in the second quarter of 2016, compared to a loss of $53.2 million in the second quarter of 2015. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from unsettled derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Any gains on our derivatives are expected to be offset by lower wellhead revenues in the future, and any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At June 30, 2016, all of our derivative contracts were recorded at their fair value, which was a net asset of $12.1 million, a decrease of $52.5 million from the $64.6 million net asset recorded as of December 31, 2015. The decrease in the net asset at June 30, 2016 as compared to December 31, 2015 was primarily due to settlements of derivative instruments since December 31, 2015, which was partially offset by an increase in oil prices on the open oil derivative contracts.

Production Expenses

Production expenses were $11.1 million in the second quarter of 2016, compared to $13.6 million in the second quarter of 2015. On a per unit basis, production expenses decreased from $8.97 per Boe in the second quarter of 2015 to $8.74 per Boe in the second quarter of 2016 due to a reduction in the aggregate dollar amount of production expenses that was partially offset by a 16% decline in production levels. Although the total producing well count increased by 4%, aggregate production expenses declined due to reductions in contract labor and maintenance costs.

Production Taxes

Lower commodity prices in the second quarter of 2016 as compared to the second quarter of 2015 has decreased our crude oil and natural gas sales, which has lowered the taxable base that is used to calculate production taxes. Production taxes were $4.2 million in the second quarter of 2016 compared to $6.9 million in the second quarter of 2015. As a percentage of oil and natural gas sales, our production taxes were 9.9% and 10.9% in the second quarter of 2016 and 2015, respectively. This decrease in production tax rates as a percentage of oil and gas sales in the second quarter of 2016 is due to a lower oil production tax rate in North Dakota, which dropped to 10% beginning in 2016.

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General and Administrative Expense

General and administrative expense was $4.6 million in the second quarter of 2016 compared to $4.3 million in the second quarter of 2015. Higher compensation expense ($0.2 million) and higher legal and professional expense ($0.2 million) was offset by lower travel expense ($0.1 million). The increase in compensation expense resulted from higher non-cash share-based compensation which was partially offset by the staff reductions in the third quarter of 2015. The increase in legal and professional expense was in part due to the Company engaging outside legal counsel to assist it in complying with requests from the SEC relating to an ongoing investigation of 2012 trading patterns in the securities of Dakota Plains Holdings, Inc. (“Dakota Plains”). Michael Reger, our chief executive officer, was an initial investor in Dakota Plains in 2008. The Company has never owned any interest in Dakota Plains. Based on the information available to it, the Company does not believe that it, or any conduct by the Company, is the focus of any investigation by a governmental agency regarding this matter.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion (“DD&A”) was $16.2 million in the second quarter of 2016 compared to $36.7 million in the second quarter of 2015. Depletion expense, the largest component of DD&A, decreased by $20.6 million in the second quarter of 2016 as compared to the second quarter of 2015. The aggregate decrease in depletion expense was driven by a 48% decrease in the depletion rate per Boe, as well as a 16% decrease in production levels. On a per unit basis, depletion expense was $12.64 per Boe in the second quarter of 2016, compared to $24.20 per Boe in the second quarter of 2015. The 2016 depletion rate per Boe was lower due to the impairment of oil and gas properties in 2015 and the first half of 2016, which lowered the depletable base. Depreciation, amortization and accretion was $0.2 million in the second quarter of 2016 and 2015, respectively. The following table summarizes DD&A expense per Boe for the second quarters of 2016 and 2015:

	Three Months Ended June 30,			
	2016	2015	Change	Change
Depletion	$12.64	$24.20	$(11.56)	(48)%
Depreciation, Amortization and Accretion	0.12	0.11	0.01	9 %
Total DD&A Expense	$12.76	$24.31	$(11.55)	(48)%

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 our properties, we recorded a non-cash ceiling test impairment of $88.9 million in the second quarter of 2016 and $282.0 million in the second quarter of 2015. The impairment charge affected our reported net income but did not reduce our cash flow.

If commodity prices remain at decreased levels, the trailing twelve-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 twelve-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 analysis in future periods.

Interest Expense

Interest expense, net of capitalized interest, was $16.0 million in the second quarter of 2016, compared to $14.4 million in the second quarter of 2015. The increase in interest expense for the second quarter of 2016 as compared to the second quarter of 2015 was primarily due to a higher average cost of borrowing between periods. In May 2015, we closed an offering of $200 million of 8.000% senior unsecured notes, which bear a higher interest rate as compared to borrowings under our revolving credit facility.

Income Tax Provision

During the second quarter of 2016, no income tax benefit was recorded on the loss before income taxes, as compared to an income tax benefit of $66.9 million or 21.1% in the second quarter of 2015. No benefit for income taxes was recorded in the second quarter of 2016 due to a $318.5 million valuation allowance placed on the net deferred tax asset in 2016 because of the uncertainty regarding their realization. For further discussion of our valuation allowance, see Note 9 to our financial statements.

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Results of Operations for the Six-Month Periods Ended June 30, 2016 and June 30, 2015

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

	Six Months Ended June 30,		
	2016	2015	% Change
Net Production:			
Oil (Bbl)	2,195,700	2,643,000	(17)%
Natural Gas and NGLs (Mcf)	1,832,322	2,384,840	(23)%
Total (Boe)	2,501,087	3,040,474	(18)%
Net Sales:			
Oil Sales	$68,115,023	$109,051,832	(38)%
Natural Gas and NGL Sales	2,780,165	4,466,649	(38)%
Gain (Loss) on Derivative Instruments, Net	(7,059,066)	3,452,235	(304)%
Other Revenue	14,339	17,117	(16)%
Total Revenues	63,850,461	116,987,833	(45)%
Average Sales Prices:			
Oil (per Bbl)	$31.02	$41.26	(25)%
Effect of Gain on Settled Derivatives on Average Price (per Bbl)	20.69	26.85	(23)%
Oil Net of Settled Derivatives (per Bbl)	51.71	68.11	(24)%
Natural Gas and NGLs (per Mcf)	1.52	1.87	(19)%
Realized Price on a Boe Basis Including all Realized Derivative Settlements	46.51	60.68	(23)%
Operating Expenses:			
Production Expenses	$23,041,232	$27,763,891	(17)%
Production Taxes	6,987,612	12,284,896	(43)%
General and Administrative Expense	8,923,677	8,609,242	4 %
Depletion, Depreciation, Amortization and Accretion	34,022,952	81,958,844	(58)%
Costs and Expenses (per Boe):			
Production Expenses	$9.21	$9.13	1 %
Production Taxes	2.79	4.04	(31)%
General and Administrative Expense	3.57	2.83	26 %
Depletion, Depreciation, Amortization and Accretion	13.60	26.96	(50)%
Net Producing Wells at Period End	208.1	199.2	4 %

Oil and Natural Gas Sales

In the first six months of 2016, our oil, natural gas and NGL sales, excluding the effect of settled derivatives, decreased 38% as compared to the first six months of 2015, driven by a 24% decrease in realized prices, excluding the effect of settled derivatives, and a 18% decrease in production. The lower average realized price in the first six months of 2016 as compared to the same period in 2015 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 six months of 2016 was $8.76 per barrel, as compared to $12.08 per barrel in the first six months of 2015.

As discussed above, we add production through drilling success as we place new wells into production and through additions from acquisitions, which is offset by the natural decline of our oil and natural gas sales from existing wells. In light of the low commodity price environment, we reduced our 2015 capital expenditure spending by 76% as compared to the prior year which lowered the number of new wells placed into production. In 2016, our capital expenditure budget was further reduced to provide a better matching of discretionary cash flow with our capital spending. Although the per well productivity improved, that was more than offset by the natural decline of oil and gas production in the first six months of 2016 due to the lower number of new wells placed into production. In addition, certain of our operators began curtailing production beginning in 2016 due to their desire to produce the wells at higher prices than currently exist. Fewer new well additions coupled with production curtailments resulted in a production volume decrease of 18% when comparing the first six months of 2016 to the same period of 2015.

Derivative Instruments

We enter into derivative instruments to manage the price risk attributable to future oil production. Our gain (loss) on derivative instruments, net was a loss of $7.1 million in the first six months of 2016, compared to a gain of $3.5 million in the first six months of 2015. 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 six months of 2016, we realized a gain on settled derivatives of $45.4 million, compared to a $71.0 million gain for the first six months of 2015. Our average realized price (including all cash derivative settlements) in the first six months of 2016 was $46.51 per Boe compared to $60.68 per Boe in the first six months of 2015. The gain on settled derivatives increased our average realized price per Boe by $18.16 in the first six months of 2016 and increased our average realized price per Boe by $23.34 in the first six months of 2015.

Mark-to-market derivative gains and losses was a loss of $52.5 million in the first six months of 2016, compared to a loss of $67.5 million in first six months of 2015. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from unsettled derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Any gains on our derivatives are expected to be offset by lower wellhead revenues in the future, and any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At June 30, 2016, all of our derivative contracts were recorded at their fair value, which was a net asset of $12.1 million, a decrease of $52.5 million from the $64.6 million net asset recorded as of December 31, 2015. The decrease in the net asset at June 30, 2016 as compared to December 31, 2015 was primarily due to settlements of derivative instruments since December 31, 2015, as well as changes in oil prices on the open oil derivative contracts.

Production Expenses

Production expenses were $23.0 million in the first six months of 2016 compared to $27.8 million in the first six months of 2015. We experience increases in operating expenses as we add new wells and maintain production from existing properties. On a per unit basis, production expenses increased from $9.13 per Boe in the first six months of 2015 to $9.21 per Boe in the first six months of 2016. On an absolute dollar basis, our production expenses in 2016 were 17% lower when compared to 2015 due primarily to lower contract labor and maintenance costs, which was partially offset by a 4% increase in the total number of net producing wells.

Production Taxes

Lower commodity prices in the first six months of 2016 as compared to the first six months of 2015 has decreased our crude oil and natural gas sales, which has lowered the taxable base that is used to calculate production taxes. Production taxes were $7.0 million in the first six months of 2016 compared to $12.3 million in the first six months of 2015. As a percentage of oil and natural gas sales, our production taxes were 9.9% and 10.8% in the first six months of 2016 and 2015, respectively. This decrease in production tax rates as a percentage of oil and gas sales in the first six months of 2016 is due to a lower oil production tax rate in North Dakota, which dropped to 10% beginning in 2016.

General and Administrative Expense

General and administrative expense was $8.9 million in the first six months of 2016 compared to $8.6 million in the first six months of 2015. Lower compensation expense ($0.2 million) and travel and other expense ($0.2 million) was offset by higher legal and professional expense ($0.7 million). The reduction in compensation expense resulted from 2015 third quarter staff reductions and lower incentive plan amounts. The increase in legal and professional expense was primarily due to the Company engaging outside

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legal counsel to assist it in complying with requests from the SEC relating to an ongoing investigation of 2012 trading patterns in the securities of Dakota Plains Holdings, Inc. ("Dakota Plains"). Michael Reger, our chief executive officer, was an initial investor in Dakota Plains in 2008. The Company has never owned any interest in Dakota Plains. Based on the information available to it, the Company does not believe that it, or any conduct by the Company, is the focus of any investigation by a governmental agency regarding this matter.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion ("DD&A") was $34.0 million in the first six months of 2016 compared to $82.0 million in the first six months of 2015. Depletion expense, the largest component of DD&A, decreased by $47.9 million in the first six months of 2016 compared to the first six months of 2015. The aggregate decrease in depletion expense was driven by a 50% decrease in the depletion rate per Boe, as well as an 18% decrease in production levels. On a per unit basis, depletion expense was $13.48 per Boe in the first six months of 2016, compared to $26.84 per Boe in the first six months of 2015. Depreciation, amortization and accretion was $0.3 million in the first six months of 2016 and 2015, respectively. The following table summarizes DD&A expense per Boe for the first six months of 2016 and 2015:

	Six Months Ended June 30,			
	2016	2015	Change	Change
Depletion	$13.48	$26.84	$(13.36)	(50)%
Depreciation, Amortization and Accretion	0.12	0.11	0.01	9 %
Total DD&A Expense	$13.60	$26.95	$(13.35)	(50)%

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, we recorded a non-cash ceiling test impairment of $193.2 million for the first six months of 2016 and $642.4 million for the first six months of 2015. The impairment charge affected our reported net income but did not reduce our cash flow.

If commodity prices remain at decreased levels, the trailing twelve-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 twelve-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 analysis in future periods.

Interest Expense

Interest expense, net of capitalized interest, was $32.1 million for the first six months of 2016 compared to $26.1 million in the first six months of 2015. The increase in interest expense for the first six months of 2016 compared to the first six months of 2015 was primarily due to a higher average cost of borrowing between periods. In May 2015, we closed an offering of $200 million of 8.000% senior unsecured notes, which bear a higher interest rate as compared to borrowings under our revolving credit facility.

Income Tax Provision

During the first six months of 2016, no income tax benefit was recorded on the loss before income taxes, as compared to an income tax benefit of $202.3 million or 29.7% in the first six months of 2015. No benefit for income taxes was recorded in the first six months of 2016 due to a $318.5 million valuation allowance placed on the net deferred tax asset in 2016 because of the uncertainty regarding their realization. For further discussion of our valuation allowance, see Note 9 to our financial statements.

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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) debt issuance cost write-off, net of tax and (ii) impairment of oil and natural gas properties, net of tax. Our Adjusted Net Income for the second quarter of 2016 was $6.5 million (representing approximately $0.10 per diluted share), compared to $11.5 million (representing approximately $0.19 per diluted share) for the second quarter of 2015. The decrease in Adjusted Net Income is primarily due to lower realized commodity prices as well as higher interest, and reduced hedging levels. Our Adjusted Net Income for the first six months of 2016 was $7.1 million (representing approximately $0.11 per diluted share), compared to $17.5 million (representing approximately $0.29 per diluted share) for the first six months of 2015. The decrease in Adjusted Net Income is primarily due to lower realized commodity prices as well as higher interest, and reduced hedging levels.

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, (vi) debt issuance cost write-off and (vii) impairment of oil and natural gas properties. Adjusted EBITDA for the second quarter of 2016 was $44.3 million, compared to Adjusted EBITDA of $70.4 million for the second quarter of 2015. The decrease in Adjusted EBITDA is primarily due to the lower average NYMEX oil prices, declining production levels, and reduced hedging levels in the second quarter of 2016 compared to the second quarter of 2015. Adjusted EBITDA for the first six months of 2016 was $80.4 million, compared to Adjusted EBITDA of $137.9 million for the first six months of 2015. The decrease in Adjusted EBITDA is primarily due to the lower average NYMEX oil prices, declining production levels, and reduced hedging levels in the first six months of 2016 compared to the first six months of 2015.

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:

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Reconciliation of Adjusted Net Income

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net Loss	$(108,978,662)	$(250,060,617)	$(235,544,415)	$(479,799,187)
Add:				
Impact of Selected Items:				
Loss on the Mark-to-Market of Derivative Instruments	30,506,698	53,193,228	52,489,716	67,524,595
Write-off of Debt Issuance Costs		—	1,089,507	—
Impairment of Oil and Natural Gas Properties	88,880,921	281,964,097	193,192,043	642,393,059
Selected Items, Before Income Taxes (Benefit)	119,387,619	335,157,325	246,771,266	709,917,654
Income Tax of Selected Items[(1)]	(3,899,825)	(73,583,617)	(4,112,781)	(212,616,501)
Selected Items, Net of Income Taxes (Benefit)	115,487,794	261,573,708	242,658,485	497,301,153
Adjusted Net Income	$6,509,132	$11,513,091	$7,114,070	$17,501,966
Weighted Average Shares Outstanding – Basic	61,180,313	60,644,635	61,071,948	60,600,652
Weighted Average Shares Outstanding – Diluted	62,079,083	60,790,352	61,361,831	60,712,210
Net Loss Per Common Share – Basic	$(1.78)	$(4.12)	$(3.86)	(7.92)
Add:				
Impact of Selected Items, Net of Income Taxes (Benefit)	1.89	4.31	3.97	8.21
Adjusted Net Income Per Common Share – Basic	$0.11	$0.19	$0.11	$0.29
Net Loss Per Common Share – Diluted	$(1.76)	$(4.11)	$(3.84)	$(7.90)
Add:				
Impact of Selected Items, Net of Income Taxes (Benefit)	1.86	4.30	3.95	8.19
Adjusted Net Income Per Common Share – Diluted	$0.10	$0.19	$0.11	$0.29

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(1) For the 2016 columns, this represents a tax impact using an estimated tax rate of 37.5% and 36.6% for the three and six months ended June 30, 2016, respectively, which includes a $40.8 million and $86.3 million adjustment for a change in valuation allowance for the three and six months ended June 30, 2016, respectively. For the 2015 columns, this represents a tax impact using an estimated tax rate of 36.9% and 37.0% for the three and six months ended June 30, 2015, respectively, which includes a $49.9 million adjustment for a change in valuation allowance for the three and six months ended June 30, 2015, respectively.

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Reconciliation of Adjusted EBITDA

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net Loss	$(108,978,662)	$(250,060,617)	$(235,544,415)	$(479,799,187)
Add:				
Interest Expense	16,046,325	14,387,693	32,145,007	26,124,240
Income Tax Benefit	—	(66,866,610)	—	(202,346,610)
Depreciation, Depletion, Amortization and Accretion	16,176,863	36,745,805	34,022,952	81,958,844
Impairment of Oil and Natural Gas Properties	88,880,921	281,964,097	193,192,043	642,393,059
Non-Cash Share Based Compensation	1,629,677	1,050,157	3,021,470	2,080,474
Write-off of Debt Issuance Costs	—	—	1,089,507	—
Loss on the Mark-to-Market of Derivative Instruments	30,506,698	53,193,228	52,489,716	67,524,595
Adjusted EBITDA	$44,261,822	$70,413,753	$80,416,280	$137,935,415

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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 for opportunities to enhance liquidity or otherwise improve our financial position.

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 86% and 87% of our total production volumes in the second quarter of 2016 and 2015, 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. We partially mitigate the price of crude oil by entering into hedging arrangements with respect to a portion of our expected oil production.

In 2015, we had derivative contracts hedging approximately 4.0 million barrels of oil, which represented 77% of our oil production, at an average price of $89.43. In the first half of 2016, we had derivative contracts hedging approximately 0.9 million barrels of oil, which represented approximately 41% of our oil production, at an average price of $90.00. As of June 30, 2016, we had derivative contracts hedging 0.9 million barrels of oil in the second half of 2016 at an average price of $65.00 per barrel and approximately 0.7 million barrels of oil in the first half of 2017 at an average price of $50.00 per barrel (see Note 11 to our 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 and unscheduled, event-driven redeterminations. In May 2016, our semi-annual borrowing base redetermination was completed and our borrowing base was established at $350 million. At June 30, 2016, we had $132.0 million of borrowings on the Revolving Credit Facility with $218.0 million of borrowing availability. Additionally, we have $700 million aggregate principal amount of outstanding 8.000% senior unsecured notes due June 1, 2020 (the "Notes").

With cash flow from operations and availability under our Revolving Credit Facility, 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.

We continually seek to maintain a financial profile that provides operational flexibility. However, as evidenced by the decline in our realized prices used in our December 31, 2015 reserve report compared to our December 31, 2014 reserve report, the decrease in oil and natural gas prices may have a negative impact on our ability to raise additional capital and/or maintain our desired levels of liquidity. At June 30, 2016, we had $819.0 million of total debt outstanding, $429.8 million of stockholders' deficit, and $3.7 million of cash on hand. We had $218.0 million of borrowing availability under our Revolving Credit Facility at June 30, 2016. At December 31, 2015, we had $835.3 million of debt outstanding, $197.6 million of stockholders' deficit and $3.4 million of cash on hand.

The significant decline in oil prices that began in the third quarter of 2014 and has lasted into 2016 has substantially decreased our cash flows from operating activities. Sustained low oil prices could significantly reduce or eliminate our planned capital expenditures. If production is not replaced through the acquisition or drilling of new wells, then our production levels will decrease due to the natural decline of production from existing wells. Reduced production levels combined with low commodity prices would lower cash flow from operations and could adversely affect our ability to meet our Revolving Credit Facility covenant requirements, which require us to maintain certain levels of working capital, as well as interest expense and secured debt coverage ratios. While we are currently in compliance with our financial covenants under the Revolving Credit Facility at June 30, 2016, there is no assurance we will be able to maintain compliance in the future.

In light of the low commodity price environment, we reduced our 2015 capital expenditure spending by 76% as compared to the prior year which lowered the number of new wells placed into production. In 2016, our capital expenditure budget was further reduced to provide a better matching of discretionary cash flow with our capital spending. Although the per well productivity improved, that was more than offset by the natural decline of oil and gas production in the first six months of 2016 due to the lower number of new wells placed into production. In addition, certain of our operators began curtailing production beginning in 2016 due to their desire to produce the wells at higher prices than currently exist. Fewer new well additions coupled with production curtailments resulted in a production volume decrease of 18% when comparing the first six months of 2016 to the same

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period of 2015. During the six months ended June 30, 2016, our cash flow exceeded capital expenditures and these excess cash flows were used to reduce outstanding borrowings under our credit facility by $18 million as of June 30, 2016 compared to December 31, 2015. While lower commodity prices will likely reduce our future borrowing capacity, with over 87% of the December 31, 2015 PV-10 value of our total proved reserves supported by producing wells, we believe we will have sufficient cash flows and adequate liquidity to fund our development plan. 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) maintain adequate liquidity and selectively participate in new drilling and completion activities, subject to economic and industry conditions and (2) pursue acquisition and disposition opportunities as available liquidity permits. 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 borrowings on our Revolving Credit Facility.

At June 30, 2016, we had a working capital deficit of $10.8 million, compared to a surplus of $43.9 million at December 31, 2015. Current assets decreased by $62.4 million and current liabilities decreased by $7.8 million at June 30, 2016, compared to December 31, 2015. The decrease in current assets is primarily due to lower cash, accounts receivable and derivative instrument balances in 2016. The reduction in accounts receivable was caused by lower commodity prices received on our production and the reduction in the balance of derivative instruments was due to hedging settlements. The change in current liabilities is primarily due to a $9.4 million decrease in accounts payable and accrued expenses balances that was due to reduced capital expenditure activities. Partially offsetting the 2016 decrease in current liabilities was $1.4 million of derivatives liability balances due to higher forward oil prices on the derivative instruments that cover 2017.

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations also are impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to fund our development activities or reduce borrowings on our Revolving Credit Facility. Short-term liquidity needs are satisfied by borrowings under our Revolving Credit Facility. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under the Revolving Credit Facility. As of June 30, 2016, we had derivative contracts hedging 0.9 million barrels of oil in the second half of 2016 at an average price of $65.00 per barrel and approximately 0.7 million barrels of oil in the first half of 2017 at an average price of $50.00 per barrel.

Our cash flows for the six months ended June 30, 2016 and 2015 are presented below:

	Six Months Ended June 30, 2016	2015
	(in thousands, unaudited)	
Net Cash Provided by Operating Activities	$58,523	$111,699
Net Cash Used for Investing Activities	(38,432)	(188,166)
Net Cash (Used for) Provided by Financing Activities	(19,814)	74,242
Net Change in Cash	$277	$(2,225)

Cash Flows from Operating Activities

Net cash provided by operating activities for the quarter ended June 30, 2016 was $58.5 million, compared to $111.7 million in the same period of the prior year. This decrease was due to lower realized prices, reduced production levels and higher interest costs. Net cash provided by operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our statements of cash flows) in the quarter ended June 30, 2016 was an increase of $7.5 million compared to a decrease of $1.9 million in the same period of the prior year.

Cash Flows from Investing Activities

Cash flows used in investing activities during the six months ended June 30, 2016 and 2015 was $38.4 million and $188.2 million, respectively. The decrease in cash used in investing activities for the first six months of 2016 as compared to the same period of 2015 was attributable to a decrease in oil and gas spending driven by a decrease in wells drilling and awaiting completion in the second quarter of 2016 as compared to the same period of 2015. Additionally, the amount of capital expenditures included in accounts payable (and thus not included in cash flows from investing activities) was $53.6 million and $110.0 million at June 30, 2016 and 2015, respectively.

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 six months ended June 30, 2016, our capitalized costs incurred for oil and natural gas properties (e.g., drilling and completion costs and other capital expenditures) amounted to $34.6 million, while the actual cash spend in this regard amounted to $38.4 million.

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. Our cash spend for development and acquisition activities for the six months ended June 30, 2016 and 2015 are summarized in the following table:

	Six Months Ended June 30,	
	2016	2015
	(in millions, unaudited)	
Drilling and Completion Costs	$34.4	$182.9
Acreage and Related Activities	3.2	4.2
Other Capital Expenditures	0.8	1.2
Total	$38.4	$188.3

Cash Flows from Financing Activities

Net cash (used for) or provided by financing activities was $(19.8) million and $74.2 million during the six months ended June 30, 2016 and 2015, respectively. For the six months ended June 30, 2016, cash used for financing activities was primarily related to repayments of our Revolving Credit Facility. For the six months ended June 30, 2015, cash sourced through financing activities was primarily due to a $200 million issuance of Notes in May 2015, which was partially offset by $5.6 million in debt issuance costs. Our long term debt at June 30, 2016 was $819.0 million, which was comprised of $687.0 million in senior unsecured notes and $132.0 million of borrowings under our Revolving Credit Facility. As of June 30, 2016, we had $218.0 million of available borrowing capacity under our 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. 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 June 30, 2016, the facility amount was $750 million, we had a borrowing base of $350.0 million and $132.0 million of borrowings on the Revolving Credit Facility.

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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 1.0% to 2.0% or LIBOR borrowings at the Adjusted LIBOR Rate (as defined in the credit agreement) plus a spread ranging from 2.0% to 3.0%. 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 June 30, 2016, the commitment fee was 0.375% and the interest rate margin was 2.3% on LIBOR loans and 1.0% 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, make investments, or maintain excess cash liquidity. In addition, as of June 30, 2016, we were 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 (through September 30, 2016). The minimum ratio of EBITDAX to interest expense that we are required to maintain begins stepping down with the quarter ending December 31, 2016, through the quarter ending March 31, 2018. We were in compliance with our financial covenants under the Revolving Credit Facility at June 30, 2016.

In May 2016, our semi-annual borrowing base redetermination was completed, and the borrowing base was reduced by 36%, to $350 million, due to the impact that lower commodity prices have had on the valuation of our proved reserves. In connection with the redetermination, the credit agreement governing the Revolving Credit Facility was amended to (i) reduce the minimum ratio of EBITDAX to interest expense that we are required to maintain (currently 2.5 to 1.0) beginning with the quarter ending December 31, 2016 and stepping down through the quarter ending March 31, 2018, (ii) increase the interest rate on borrowings by 50 basis points and (iii) limit our ability to maintain excess cash liquidity without using it to reduce outstanding borrowings under the Revolving Credit Facility.

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% of 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, we 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 could have redeemed 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."

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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 throughout 2015 and into 2016. The lower commodity pricing has reduced service costs. If service cost pricing remains at the current 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, 2015 are included in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

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 Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

A description of our critical accounting policies was provided in Note 2 to our financial statements provided in Part II, Item 8 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

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, 2015 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 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 on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net 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 June 30, 2016, we had entered into derivative agreements covering 0.9 million barrels for the remainder of 2016 and 0.7 million barrels for the first six months of 2017.

The following table reflects open commodity swap contracts as of June 30, 2016, the associated volumes and the corresponding fixed price.

Settlement Period	Oil (Barrels)	Fixed Price ($)
Swaps-Crude Oil		
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
01/01/17 – 06/30/17	360,000	50.00
01/01/17 – 06/30/17	180,000	50.01
01/01/17 – 06/30/17	180,000	49.99

The following table reflects the weighted average price of open commodity swap derivative contracts as of June 30, 2016, by year with associated volumes.

Year	Volumes (Bbl)	Weighted Average Price ($)
2016	900,000	65.00
2017	720,000	50.00
2018 and beyond	—	—

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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 quarter ended June 30, 2016, we had $125.4 million in average outstanding borrowings under our Revolving Credit Facility at a weighted average rate of 2.4%. 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 2.0% to 3.0% 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 1.0% to 2.0%, 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 principal, our borrowings are rolled over and the interest rate is reset based on the current LIBOR or prime rate as applicable. As a result, changes in interest rates can impact results of operations and cash flows. A 1% increase in short-term interest rates on our floating-rate debt outstanding at June 30, 2016 would cost us approximately $1.3 million in additional annual interest expense.

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 June 30, 2016, our management, including our Chief Executive Officer and Chief Financial Officer, had evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) pursuant to Rule 13a-15(b) under the Exchange Act. Based upon and as of the date of the evaluation, our Chief Executive Officer and Chief Financial Officer concluded that information required to be disclosed is recorded, processed, summarized and reported within the specified periods and is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure of material information required to be included in our periodic SEC reports. Based on the foregoing, our management determined that our disclosure controls and procedures were effective as of June 30, 2016.

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 June 30, 2016, 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, 2015.

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 June 30, 2016.

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 April 1, 2016 to April 30, 2016	22,305	$ 3.82	—	$ 108.3 million
Month #2 May 1, 2016 to May 31, 2016	—	—	—	108.3 million
Month #3 June 1, 2016 to June 30, 2016	15,540	4.55	—	108.3 million
Total	37,845	$ 4.12	—	$ 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 June 30, 2016 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.

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SIGNATURES

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

NORTHERN OIL AND GAS, INC.

Date:	August 5, 2016	By:	/s/ Michael L. Reger
			Michael L. Reger, Chief Executive Officer and Director
Date:	August 5, 2016	By:	/s/ Thomas W. Stoelk
			Thomas W. Stoelk, Chief Financial Officer

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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	Amended and Restated Articles of Incorporation of Northern Oil and Gas, Inc. dated June 1, 2016	Filed herewith
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
10.1*	Amended and Restated Employment Agreement by and between Thomas Stoelk and Northern Oil and Gas, Inc., dated April 8, 2016	Incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed with the SEC on April 8, 2016
10.2*	Performance-Based Restricted Stock Award Agreement, dated April 8, 2016, between Northern Oil and Gas, Inc. and Thomas Stoelk	Incorporated by reference to Exhibit 10.2 to the Registrant’s Current Report on Form 10-Q filed with the SEC on May 10, 2016
10.3*	Amended and Restated Employment Agreement by and between Erik Romslo and Northern Oil and Gas, Inc., dated April 8, 2016	Incorporated by reference to Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed with the SEC on April 8, 2016
10.4	Eighth Amendment to Third Amended and Restated Credit Agreement, dated May 6, 2016, by and 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 May 10, 2016
10.5*	Northern Oil and Gas, Inc. 2013 Incentive Plan (as amended May 26, 2016)	Incorporated by reference to Appendix B to the Registrant's Definitive Proxy Statement filed with the SEC on April 22, 2016
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 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18 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.