UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2021

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________ to____________

Commission File No. 001-33999

NORTHERN OIL AND GAS, INC.

(Exact Name of Registrant as Specified in Its Charter)

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

601 Carlson Pkwy – Suite 990
Minnetonka, Minnesota 55305
(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)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.001	NOG	NYSE American

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every interactive data file required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large Accelerated Filer ☐	Accelerated Filer ☒
Non-Accelerated Filer ☐	Smaller Reporting Company ☐
	Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

As of August 4, 2021, there were 66,172,097 shares of our common stock, par value $0.001, outstanding.

GLOSSARY OF TERMS

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

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

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

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

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

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

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

"*MMBoe*." One million Boe.

"*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 a stratigraphic horizon (rock layer or formation) known to be productive for the purpose of extracting proved crude oil, NGL, or natural gas reserves.

"*Differential.*" The difference between a benchmark price of crude oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

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

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

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

"*NYMEX*." The New York Mercantile Exchange.

"*OPEC*." The Organization of Petroleum Exporting Countries.

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

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

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

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

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

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

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

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

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

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

"Workover." Operations on a producing well to restore or increase production.

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

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

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

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

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

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

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

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

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the 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.

NORTHERN OIL AND GAS, INC.
FORM 10-Q

June 30, 2021

C O N T E N T S

PART I - FINANCIAL INFORMATION

Item 1. ***Condensed Financial Statements.***

NORTHERN OIL AND GAS, INC.
CONDENSED BALANCE SHEETS

(In thousands, except par value and share data)	June 30, 2021	December 31, 2020
Assets	(Unaudited)	
Current Assets:		
Cash and Cash Equivalents	$ 4,843	$ 1,428
Accounts Receivable, Net	131,165	71,015
Advances to Operators	433	476
Prepaid Expenses and Other	2,705	1,420
Derivative Instruments	518	51,290
Total Current Assets	139,664	125,629
Property and Equipment:		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	4,638,415	4,393,533
Unproved	21,347	10,031
Other Property and Equipment	2,501	2,451
Total Property and Equipment	4,662,263	4,406,015
Less – Accumulated Depreciation, Depletion and Impairment	(3,732,183)	(3,670,811)
Total Property and Equipment, Net	930,080	735,204
Derivative Instruments	32	111
Acquisition Deposit	9,400	—
Other Noncurrent Assets, Net	12,634	11,145
Total Assets	$ 1,091,810	$ 872,089
Liabilities and Stockholders' Equity (Deficit)		
Current Liabilities:		
Accounts Payable	$ 49,186	$ 35,803
Accrued Liabilities	91,724	68,673
Accrued Interest	16,877	8,341
Derivative Instruments	140,694	3,078
Contingent Consideration	513	493
Current Portion of Long-term Debt	—	65,000
Other Current Liabilities	1,843	1,087
Total Current Liabilities	300,837	182,475
Long-term Debt	801,998	879,843
Derivative Instruments	127,526	14,659
Asset Retirement Obligations	26,176	18,366
Other Noncurrent Liabilities	3,490	50
Total Liabilities	$ 1,260,027	$ 1,095,393
Commitments and Contingencies (Note 8)		
Stockholders’ Equity (Deficit)		

Preferred Stock, Par Value $.001; 5,000,000 Shares Authorized; 2,218,732 Series A Shares Outstanding at 6/30/2021 2,218,732 Series A Shares Outstanding at 12/31/2020	2	2
Common Stock, Par Value $.001; 135,000,000* Shares Authorized; 66,164,399* Shares Outstanding at 6/30/2021 45,908,779* Shares Outstanding at 12/31/2020	468	448
Additional Paid-In Capital	1,792,589	1,556,602
Retained Deficit	(1,961,276)	(1,780,356)
Total Stockholders' Equity (Deficit)	(168,217)	(223,304)
Total Liabilities and Stockholders' Equity (Deficit)	$ 1,091,810	$ 872,089

*Adjusted for the 1-for-10 reverse stock split. See Note 5.

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF OPERATIONS
(UNAUDITED)

(In thousands, except share and per share data)	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Revenues				
Oil and Gas Sales	$ 225,717	$ 20,664	$ 383,048	$ 150,860
Gain (Loss) on Commodity Derivatives, Net	(200,912)	(72,638)	(336,847)	303,943
Other Revenue	—	3	1	12
Total Revenues	24,805	(51,971)	46,202	454,815
Operating Expenses				
Production Expenses	42,699	26,638	77,010	63,974
Production Taxes	18,514	1,917	31,967	13,813
General and Administrative Expense	7,604	4,710	14,388	9,580
Depletion, Depreciation, Amortization and Accretion	30,908	36,756	62,128	98,565
Impairment Expense	—	762,716	—	762,716
Total Operating Expenses	99,725	832,737	185,493	948,648
Loss From Operations	(74,920)	(884,708)	(139,291)	(493,833)
Other Income (Expense)				
Interest Expense, Net of Capitalization	(15,024)	(13,957)	(28,534)	(30,508)
Gain (Loss) on Unsettled Interest Rate Derivatives, Net	121	(752)	362	(1,429)
Gain (Loss) on Extinguishment of Debt, Net	(494)	217	(13,087)	(5,310)
Contingent Consideration Loss	(250)	—	(375)	—
Other Income (Expense)	4	—	5	—
Total Other Income (Expense)	(15,643)	(14,492)	(41,629)	(37,247)
Loss Before Income Taxes	(90,563)	(899,200)	(180,920)	(531,080)
Income Tax Provision (Benefit)	—	—	—	(166)
Net Loss	$ (90,563)	$ (899,200)	$ (180,920)	$ (530,914)
Cumulative Preferred Stock Dividend	(3,719)	(3,788)	(7,550)	(7,517)
Net Loss Attributable to Common Stockholders	$ (94,282)	$ (902,988)	$ (188,470)	$ (538,431)
Net Loss Per Common Share – Basic*	$ (1.55)	$ (21.74)	$ (3.27)	$ (13.15)
Net Loss Per Common Share – Diluted*	$ (1.55)	$ (21.74)	$ (3.27)	$ (13.15)
Weighted Average Common Shares Outstanding – Basic*	60,694,795	41,535,604	57,633,454	40,950,929
Weighted Average Common Shares Outstanding – Diluted*	60,694,795	41,535,604	57,633,454	40,950,929

*Adjusted for the 1-for-10 reverse stock split. See Note 5.

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Six Months Ended June 30,	
(In thousands)	**2021**	**2020**
Cash Flows from Operating Activities		
Net Loss	$ (180,920)	$ (530,914)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Depletion, Depreciation, Amortization and Accretion	62,128	98,565
Amortization of Debt Issuance Costs	1,873	2,776
Loss on Extinguishment of Debt	13,087	5,310
Amortization of Bond Premium on Long-term Debt	(130)	(570)
Deferred Income Taxes	—	210
Unrealized (Gain) Loss of Derivative Instruments	301,333	(193,570)
Loss on Contingent Consideration	375	—
Stock-Based Compensation Expense	1,549	2,293
Impairment Expense	—	762,716
Other	2,675	(116)
Changes in Working Capital and Other Items:		
Accounts Receivable, Net	(59,960)	65,055
Prepaid and Other Expenses	(1,286)	(238)
Accounts Payable	13,537	(1,546)
Accrued Interest	8,338	(3,733)
Accrued Liabilities and Expenses	6,353	(3,999)
Net Cash Provided by Operating Activities	168,952	202,239
Cash Flows from Investing Activities		
Drilling and Development Capital Expenditures	(73,296)	(164,242)
Acquisition of Oil and Natural Gas Properties	(130,794)	(25,491)
Acquisition Deposit	(9,400)	(774)
Purchases of Other Property and Equipment	(51)	(7)
Net Cash Used for Investing Activities	(213,541)	(190,514)
Cash Flows from Financing Activities		
Advances on Revolving Credit Facility	299,000	25,000
Repayments on Revolving Credit Facility	(568,000)	(37,000)
Repurchases of Second Lien Notes due 2023	(295,918)	(13,514)
Repayment of Unsecured VEN Bakken Note due 2022	(130,000)	—
Debt Issuance Costs Paid	(12,436)	(37)
Issuance of Common Stock	228,199	—
Issuance of Unsecured Notes due 2028	550,000	—
Restricted Stock Surrenders - Tax Obligations	(839)	(404)
Preferred Dividends Paid	(22,002)	—
Net Cash Provided (Used) for Financing Activities	48,004	(25,955)
Net Increase (Decrease) in Cash and Cash Equivalents	3,415	(14,230)
Cash and Cash Equivalents - Beginning of Period	1,428	16,068
Cash and Cash Equivalents - End of Period	4,843	1,838

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF STOCKHOLDERS' EQUITY
(UNAUDITED)

(In thousands, except share data)	Common Stock*		Preferred Stock		Additional Paid-In	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount	Capital	(Deficit)	(Deficit)
December 31, 2020	45,908,779	$ 448	2,218,732	$ 2	$ 1,556,602	$ (1,780,357)	$ (223,304)
Issuance of Common Stock	138,297	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	916	—	916
Restricted Stock Surrenders - Tax Obligations	(60,529)	—	—	—	(837)	—	(837)
Equity Offerings, Net of Issuance Costs	14,375,000	14	—	—	132,885	—	132,900
Net Loss	—	—	—	—	—	(90,357)	(90,357)
March 31, 2021	60,361,547	$ 462	2,218,732	$ 2	$ 1,689,567	$ (1,870,714)	$ (180,682)
Issuance of Common Stock	30,957	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	851	—	851
Restricted Stock Surrenders - Tax Obligations	(82)	—	—	—	(2)	—	(2)
Equity Offerings, Net of Issuance Costs	5,750,000	6	—	—	95,293	—	95,299
Issuance of Common Stock Warrants	—	—	—	—	30,512	—	30,512
Contingent Consideration Settlements	21,977	—	—	—	354	—	354
Preferred Stock Dividends	—	—	—	—	(22,002)	—	(22,002)
Common Stock Dividends Declared, $0.03 per Share	—	—	—	—	(1,985)	—	(1,985)
Net Loss	—	—	—	—	—	(90,563)	(90,563)
June 30, 2021	66,164,399	$ 468	2,218,732	$ 2	$ 1,792,589	$ (1,961,276)	$ (168,217)

(In thousands, except share data)	Common Stock*		Preferred Stock		Additional Paid-In	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount	Capital	(Deficit)	(Deficit)
December 31, 2019	40,608,518	$ 406	1,500,000	$ 2	$ 1,431,438	$ (873,203)	$ 558,643
Issuance of Common Stock	5,000	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,263	—	1,263
Restricted Stock Surrenders - Tax Obligations	(33,200)	—	—	—	(396)	—	(396)
Issuance of Preferred Stock, Net of Issuance Costs	—	—	794,702	1	81,211	—	81,212
Net Income	—	—	—	—	—	368,286	368,286
March 31, 2020	40,580,318	$ 406	2,294,702	$ 2	$ 1,513,516	$ (504,917)	$ 1,009,007
Issuance of Common Stock	219,562	2	—	—	—	—	2
Restricted Stock Forfeitures	(271)	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,313	—	1,313
Restricted Stock Surrenders - Tax Obligations	(944)	—	—	—	(8)	—	(8)
Issuance under Debt Exchange Agreements	2,845,326	28	—	—	29,586	—	29,615
Net Loss	—	—	—	—	—	(899,200)	(899,200)
June 30, 2020	43,643,991	$ 436	2,294,702	$ 2	$ 1,544,407	$ (1,404,117)	$ 140,729

*Adjusted for the 1-for-10 reverse stock split. See Note 5.

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

NOTES TO CONDENSED FINANCIAL STATEMENTS
JUNE 30, 2021
(UNAUDITED)

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the "Company," "Northern," "our" and words of similar import), a Delaware 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 American market under the symbol "NOG".

Northern's principal business is crude oil and natural gas exploration, development, and production with operations in the United States. The Company's primary strategy is investing in non-operated minority working and mineral interests in oil and gas properties in the United States.

NOTE 2 BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The financial information included herein is unaudited. The balance sheet as of December 31, 2020 has been derived from the Company's audited financial statements for the year ended December 31, 2020. 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, 2020, which were included in the Company's 2020 Annual Report on Form 10-K for the fiscal year ended December 31, 2020.

Reverse Stock Split

On September 18, 2020, the Company effected a 1-for-10 reverse stock split of its common stock. Unless otherwise noted, impacted amounts and share information included in the financial statements and notes thereto, and elsewhere in this Form 10-Q, have been retroactively adjusted as if the reverse stock split occurred on the first day of the first period presented. Certain amounts may be slightly different than previously reported due to the settlement of fractional shares as a result of the reverse stock split and rounding. See Note 5 below for more information regarding the reverse stock split.

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 reserves, which includes limited control over future development plans as a non-operator, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, fair value of contingent consideration, acquisition date fair values of assets acquired and liabilities assumed, impairment of crude oil and natural gas properties, asset retirement obligations and deferred income taxes. Actual results may differ from those estimates.

The Company considered the impact of the novel coronavirus 2019 ("COVID-19") pandemic on the assumptions and estimates used by management in the unaudited condensed financial statements for the reporting periods presented. Management's estimates and assumptions were based on historical data and consideration of future market conditions. Given the uncertainty inherent in any projection, which is heightened by the possibility of unforeseen additional impacts from the COVID-19 pandemic, actual results may differ from the estimates and assumptions used, and conditions may change, which could materially affect amounts reported in the unaudited condensed financial statements in the near term.

Adopted and Recently Issued Accounting Pronouncements

In December 2019, the FASB issued ASU 2019-12, Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes, which simplifies the accounting for income taxes by removing certain exceptions to the general principles and also simplification of areas such as separate entity financial statements and interim recognition of enactment of tax laws or rate changes. ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, including interim reporting periods within those years. The Company adopted the new standard on January 1, 2021 on a prospective basis, which did not have a material impact on its financial position, results of operations, or cash flows.

In March 2020, the FASB issued ASU No. 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting ("ASU 2020-04") followed by ASU No. 2021-01, Reference Rate Reform (Topic 848): Scope ("ASU 2021-01"), issued in January 2021 to provide clarifying guidance regarding the scope of Topic 848. ASU 2020-04 was issued to provide optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. Generally, the guidance is to be applied as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020, or prospectively from a date within an interim period that includes or is subsequent to March 12, 2020, up to the date that the financial statements are available to be issued. ASU 2020-04 and ASU 2021-01 are effective for all entities through December 31, 2022. The Company has not elected to use the optional guidance and continues to evaluate the options provided by ASU 2020-04 and ASU 2021-01.

Revenue Recognition

The Company's revenues are primarily derived from its interests in the sale of oil and natural gas production. The Company recognizes revenue from its interests in the sales of crude oil and natural gas in the period that its performance obligations are satisfied. Performance obligations are satisfied when the customer obtains control of product, when the Company has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sales of oil and natural gas are made under contracts which the third-party operators of the wells have negotiated with customers, which typically include variable consideration that is based on pricing tied to local indices and volumes delivered in the current month. The Company receives payment from the sale of oil and natural gas production from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in trade receivables, net in the balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received, however, differences have been and are insignificant. Accordingly, the variable consideration is not constrained.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption in accordance with ASC 606. The exemption, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company's oil is typically sold at delivery points under contract terms that are common in our industry. The Company's natural gas produced is delivered by the well operators to various purchasers at agreed upon delivery points under a limited number of contract types that are also common in our industry. Regardless of the contract type, the terms of these contracts compensate the well operators for the value of the oil and natural gas at specified prices, and then the well operators will remit payment to the Company for its share in the value of the oil and natural gas sold.

A wellhead imbalance liability equal to the Company's share is recorded to the extent that the Company's well operators have sold volumes in excess of its share of remaining reserves in an underlying property. However, for the three and six months ended June 30, 2021 and 2020, 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.

The Company's disaggregated revenue has two primary sources: oil sales, and natural gas and NGL sales. Substantially all of the Company's oil and gas sales come from three geographic areas in the United States: the Williston Basin (North Dakota and Montana), the Appalachian Basin (Pennsylvania), and the Permian Basin (New Mexico and Texas). The following tables present the disaggregation of the Company's oil revenues and natural gas and NGL revenues by basin for the three and six months ended June 30, 2021 and 2020.

(In thousands)	Three Months Ended June 30, 2021 Williston	Permian	Appalachian	Total	Three Months Ended June 30, 2020 Williston	Permian	Appalachian	Total
Oil Revenues	$ 181,872	$ 2,745	$ —	$ 184,617	$ 28,784	$ —	$ —	$ 28,784
Natural Gas and NGL Revenues	29,855	210	11,035	41,100	(8,120)	—	—	(8,120)
Total	$ 211,727	$ 2,955	$ 11,035	$ 225,717	$ 20,664	$ —	$ —	$ 20,664

(In thousands)	Six Months Ended June 30, 2021 Williston	Permian	Appalachian	Total	Six Months Ended June 30, 2020 Williston	Permian	Appalachian	Total
Oil Revenues	$ 315,373	$ 4,543	$ —	$ 319,916	$ 145,116	$ —	$ —	$ 145,116
Natural Gas and NGL Revenues	51,763	334	11,035	63,132	5,744	—	—	5,744
Total	$ 367,136	$ 4,877	$ 11,035	$ 383,048	$ 150,860	$ —	$ —	$ 150,860

Concentrations of Market, Credit Risk and Other Risks

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, economic disruptions resulting from the COVID-19 pandemic, 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, indirectly via the third-party operators of the wells, from purchasers of its crude oil and natural gas production. While certain of these customers, as well as third-party operators of the wells, 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 have been immaterial.

As a non-operator, 100% of the Company’s wells are operated by third-party operating partners. As a result, the Company is highly dependent on the success of these third-party operators. If they are not successful in the development, exploitation, production and exploration activities relating to the Company’s leasehold interests, or are unable or unwilling to perform, the Company’s financial condition and results of operation could be adversely affected. These risks are heightened in a low commodity price environment, which may present significant challenges to these third-party operators. The Company’s third-party operators will make decisions in connection with their operations that may not be in the Company’s best interests, and the Company may have little or no ability to exercise influence over the operational decisions of its third-party operators. For the six months ended June 30, 2021, the Company’s top four operators made up 57% of total oil and gas sales, compared to51% for the six months ended June 30, 2020.

The Company faces concentration risk due to the fact that a substantial majority of its oil and natural gas revenue is sourced from North Dakota. Recent acquisitions have diversified our portfolio to include New Mexico and Pennsylvania. But the Company remains disproportionately exposed to risks affecting a limited number of geographic areas of operations.

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 counterparties 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.

Net Income (Loss) Per Common Share

Basic earnings per share (“EPS”) are computed by dividing net income (loss) attributable to common stockholders (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) attributable to common stockholders by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include shares issuable upon exercise of stock options or warrants and vesting of restricted stock awards, and shares issuable upon conversion of the Series A Preferred Stock (see Note 5). The number of potential common shares outstanding are calculated using the treasury stock or if-converted method.

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three and six months ended June 30, 2021 and 2020 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands, except share and per share data)	**2021**	**2020**	**2021**	**2020**
Net Income (Loss)	$ (90,563)	$ (899,200)	$ (180,920)	$ (530,914)
Less: Cumulative Dividends on Preferred Stock	(3,719)	(3,788)	(7,550)	(7,517)
Net Income (Loss) Attributable to Common Stock	$ (94,282)	$ (902,988)	$ (188,470)	$ (538,431)
Weighted Average Common Shares Outstanding:				
Weighted Average Common Shares Outstanding – Basic	60,694,795	41,535,604	57,633,454	40,950,929
Plus: Dilutive Effect of Restricted Stock and Warrants	—	—	—	—
Plus: Dilutive Effect of Preferred Shares	—	—	—	—
Weighted Average Common Shares Outstanding – Diluted	60,694,795	41,535,604	57,633,454	40,950,929
Net Income (Loss) per Common Share:				
Basic	$ (1.55)	$ (21.74)	$ (3.27)	$ (13.15)
Diluted	$ (1.55)	$ (21.74)	$ (3.27)	$ (13.15)
Shares Excluded from EPS Due to Anti-Dilutive Effect:				
Restricted Stock and Warrants	135,983	30,163	128,055	40,005
Preferred Stock	9,698,756	100,208,753	9,698,756	96,747,545

Supplemental Cash Flow Information

The following reflects the Company’s supplemental cash flow information:

	Six Months Ended June 30,	
(In thousands)	**2021**	**2020**
Supplemental Cash Items:		
Cash Paid During the Period for Interest, Net of Amount Capitalized	$ 26,547	$ 29,117
Cash Paid During the Period for Income Taxes	—	—
Non-cash Investing Activities:		
Oil and Natural Gas Properties Included in Accounts Payable and Accrued Liabilities	101,018	92,537
Capitalized Asset Retirement Obligations	7,982	294
Contingent Consideration	354	—
Compensation Capitalized on Oil and Gas Properties	219	284
Issuance of Common Stock - Acquisitions of Oil and Natural Gas Properties	30,512	—
Non-cash Financing Activities:		
Common Stock Dividends Declared	1,985	—
Issuance of Common Stock for Second Lien Notes Repurchase	—	29,615
Issuance of Preferred Stock for Second Lien Notes Repurchase	—	81,212

NOTE 3 CRUDE OIL AND NATURAL GAS PROPERTIES

The Company follows the full cost method of accounting for crude oil and natural gas operations whereby all costs related to the exploration and development of crude oil and natural gas properties are 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 production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred.

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 Company did not have any impairment of its proved oil and gas properties for the three and six months ended June 30, 2021. As a result of low commodity prices and their effect on the proved reserve values of properties during 2020, the Company recorded a non-cash ceiling test impairment of $762.7 million for both the three and six months ended June 30, 2020.

The book 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. Acquired assets and liabilities assumed are recorded 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.

2021 Acquisitions

In addition to the Reliance Acquisition (defined below), the Company acquired oil and natural gas properties, through a number of independent transactions, for a total of $24.7 million and $29.1 million during the three and six months ended June 30, 2021, respectively. These amounts include $7.0 million and $8.8 million, respectively, of associated development costs.

Reliance Acquisition

On April 1, 2021, the Company completed the acquisition of certain oil and gas properties, interests and related net assets (the "Acquired Net Assets") from Reliance Marcellus, LLC (the "Reliance Acquisition"), effective July 1, 2020. At closing, the Acquired Net Assets included approximately 95.3 net producing wells and 24.9 net wells in progress, as well as approximately 61,712 net acres in the Appalachian Basin in Pennsylvania. In addition, the Company assumed minimum volume commitment contracts. The Reliance Acquisition was completed pursuant to the purchase and sales agreement between the Company and Reliance Marcellus, LLC ("Reliance"), dated February 3, 2021.

The total estimated consideration paid by the Company was $139.7 million, consisting of (i) warrants to purchase 3,250,000 shares of the Company's common stock with an exercise price equal to $14.00 per share and a total estimated fair value of $30.5 million and (ii) cash purchase consideration of $109.2 million from equity offering proceeds.

The results of operations from the acquisition from the April 1, 2021 closing date through June 30, 2021, represented approximately $11.0 million of revenue and $1.9 million of income from operations. The Company incurred $5.5 million of transactions costs in connection with the acquisition, which are included in general and administrative expense in the condensed statement of operations. The following table reflects the fair values of the net assets and liabilities as of the date of acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	138,807
Unproved oil and natural gas properties		10,912
Total assets acquired		149,719
Asset retirement obligations		(6,549)
Minimum volume commitment liability		(3,442)
Net assets acquired	$	139,727
Fair value of consideration paid for net assets:		
Cash consideration	$	109,215
Issuance of Common Stock Warrants (3.25 million shares at $14.00 per share)		30,512
Total fair value of consideration transferred	$	139,727

Pro Forma Information

The following summarized unaudited pro forma condensed statements of operations information for the three and six months ended June 30, 2020, and for the six months ended June 30, 2021, assumes that the Reliance Acquisition occurred as of January 1, 2020. There is no pro forma information included for the three months ended June 30, 2021, because the Company's actual financial results for such period fully reflect the Reliance Acquisition. The Company prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma information may not be indicative of the results that would have occurred had the Company completed the acquisition as of January 1, 2020, or that will be attained in the future.

(In thousands)	Three Months Ended June 30, 2020	Six Months Ended June 30, 2020	Six Months Ended June 30, 2021
Total Revenues	$ (41,719)	$ 476,648	$ 59,850
Net Loss	(901,427)	(534,931)	(180,297)

2020 Acquisitions

The Company acquired oil and natural gas properties, through a number of independent transactions, for a total of $0.4 million and $25.9 million during the three and six months ended June 30, 2020, respectively. These amounts include $0.1 million and $18.4 million, respectively, of development costs that occurred prior to the closings of the acquisitions.

Unproved Properties

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

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

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.

Capitalized costs associated with impaired unproved properties, which includes leases that have expired or have been deemed uneconomic, 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, 2021 and 2020, unproved properties of $0.5 million and $0.4 million, respectively, were impaired. For the six months ended June 30, 2021 and 2020, unproved properties of $0.6 million and $2.0 million, respectively, were impaired.

NOTE 4 LONG-TERM DEBT

The Company's long-term debt consisted of the following as of the dates indicated:

(In thousands)	June 30, 2021	December 31, 2020
Revolving Credit Facility	$ 263,000	$ 532,000
Unsecured Notes due 2028	550,000	—
Second Lien Notes due 2023	—	287,755
Unsecured VEN Bakken Note due 2022	—	130,000
Total principal	813,000	949,755
Unamortized debt discounts and premiums	—	2,041
Unamortized debt issuance costs[1]	(11,002)	(6,953)
Total debt	801,998	944,843
Less current portion of long-term debt	—	(65,000)
Total long-term debt	$ 801,998	$ 879,843

[1] Debt issuance costs related to the Company's revolving credit facility of $6.2 million and $6.5 million as of June 30, 2021 and December 31, 2020, respectively, are recorded in "Other Noncurrent Assets, Net" on the balance sheets.

2021 Financing Transactions

During the six months ended June 30, 2021, the Company completed a series of financing transactions related to its debt arrangements, which are summarized as follows:

- completed a common stock offering in February 2021 with net proceeds of $132.9 million, which was primarily intended to finance the cash purchase price for the Reliance Acquisition that closed on April 1, 2021;
- completed another common stock offering in June 2021 with net proceeds of $95.3 million, which was primarily intended to finance the cash purchase price for oil and gas property acquisitions in the Permian Basin that primarily closed in the third quarter of 2021, but in the interim reduced the Company's outstanding indebtedness;
- issued $550.0 million in aggregate principal amount of new 8.125% senior unsecured notes due 2028 (the "2028 Notes"), priced at par, with estimated net proceeds of $538.4 million;
- fully repaid and retired all $130.0 million in principal amount of the Company's 6.0% senior unsecured promissory note due 2022 (the "Unsecured VEN Bakken Note");
- redeemed and retired $272.1 million in aggregate principal amount of the Company's 8.500% senior secured second lien notes due 2023 (the "Second Lien Notes") pursuant to a cash tender offer at a cost of $280.2 million including premiums, and subsequently redeemed and retired the remaining $15.7 million in aggregate principal amount of the Second Lien Notes at a cost of $16.0 million including premiums;
- reduced the amount of borrowings outstanding under the Revolving Credit Facility (defined below) from $532.0 million as of December 31, 2020 to $263.0 million as of June 30, 2021.

Revolving Credit Facility

On November 22, 2019, the Company entered into a Second Amended and Restated Credit Agreement (the “Revolving Credit Facility”) with Wells Fargo Bank, National Association, as administrative agent, and the lenders from time to time party thereto, which amended and restated the Company’s prior revolving credit facility that was entered into on October 5, 2018. The Revolving Credit Facility is scheduled to mature on November 22, 2024.

The Revolving Credit Facility is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to the Company and its subsidiaries’ (if any) oil and gas properties. As of June 30, 2021, the borrowing base was $725.0 million and the aggregate elected commitment amount was $660.0 million. In order to borrow in excess of the elected commitment amount, the Company would need to find new or existing lenders willing to provide the additional commitments. The borrowing base will be redetermined semiannually on or around April 1st and October 1st, with one interim “wildcard” redetermination available between scheduled redeterminations. The April 1st scheduled redetermination shall be based on a January 1st engineering report audited by a third party (reasonably acceptable by the Agent). The aggregate elected commitment amount may be increased semi-annually upon each scheduled borrowing base redetermination, and up to two times between each scheduled redetermination.

At the Company’s option, borrowings under the Revolving Credit Facility shall bear interest at the base rate or LIBOR plus an applicable margin. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank’s prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from100 to 200 basis points, and the applicable margin for LIBOR loans ranges from200 to 300 basis points, in each case depending on the percentage of the borrowing base utilized.

The Revolving Credit Facility contains negative covenants that limit the Company’s ability, among other things, to pay dividends, incur additional indebtedness, maintain excess cash liquidity, sell assets, enter into certain derivatives contracts, change the nature of its business or operations, merge, consolidate, or make certain types of investments. In addition, the Revolving Credit Facility requires that the Company comply with the following financial covenants: (i) as of the date of determination, the ratio of total net debt to EBITDAX (as defined in the Revolving Credit Facility) shall be no more than 3.50 to 1.00, measured on a pro forma rolling four quarter basis, and (ii) the current ratio (defined as consolidated current assets including unused amounts of the total commitments, but excluding non-cash assets under FASB ASC 815, divided by consolidated current liabilities excluding current non-cash obligations under FASB ASC 815 and current maturities under the Revolving Credit Facility) shall not be less than 1.00 to 1.00. The Company is in compliance with these financial covenants as of June 30, 2021.

The Company’s obligations under the Revolving Credit Facility may be accelerated, subject to customary grace and cure periods, upon the occurrence of certain Events of Default (as defined in the Revolving Credit Facility). Such Events of Default include customary events for a financing agreement of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness of us or the Company’s subsidiaries, defaults related to judgments and the occurrence of a Change in Control (as defined in the Revolving Credit Facility).

The Company’s obligations under the Revolving Credit Facility are secured by mortgages on not less than90% of the value of proven reserves associated with the oil and gas properties included in the determination of the borrowing base. Additionally, the Company entered into a Guaranty and Collateral Agreement in favor of the Agent for the secured parties, pursuant to which the Company’s obligations under the Revolving Credit Facility are secured by a first priority security interest in substantially all of the Company’s assets.

Unsecured Notes due 2028

On February 18, 2021, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the “2028 Notes Indenture”), pursuant to which the Company issued $550.0 million in aggregate principal amount of the 2028 Notes. The proceeds were used primarily to refinance existing indebtedness, and for general corporate purposes. The 2028 Notes will mature on March 1, 2028. Interest on the 2028 Notes is payable semi-annually in arrears on each March 1 and September 1, commencing September 1, 2021, to holders of record on the February 15 and August 15 immediately preceding the related interest payment date, at a rate of 8.125% per annum.

Prior to March 1, 2024, the Company may redeem all or a part of the 2028 Notes at a redemption price equal to100% of the principal amount of the 2028 Notes redeemed, plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On or after March 1, 2024, the Company may redeem all or a part of the 2028 Notes at redemption prices (expressed as percentages of principal amount) equal to 104.063% for the twelve-month period beginning on March 1, 2024, 102.031% for the twelve-month period beginning on March 1, 2025, and 100% beginning on March 1, 2026, plus accrued and unpaid interest to the redemption date.

The 2028 Notes Indenture contains covenants that, among other things, limit the Company's ability and the ability of its restricted subsidiaries, if any, to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends or distributions in respect of equity interests or redeem, repurchase or retire equity securities or subordinated indebtedness; (iii) transfer or sell certain assets; (iv) make investments; (v) create liens to secure indebtedness; (vi) enter into agreements that restrict dividends or other payments from any non-guarantor subsidiary to the Company; (vii) consolidate with or merge with or into, or sell substantially all of the Company's assets to, another person; (viii) enter into transactions with affiliates; and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications, and many of these covenants will be terminated if the 2028 Notes achieve an investment grade rating from either Moody's Investors Services, Inc. or S&P Global Ratings.

The 2028 Notes Indenture contains customary events of default, including, but not limited to: (i) default for 30 days in the payment when due of interest on the 2028 Notes; (ii) default in payment when due of the principal of, or premium, if any, on the 2028 Notes; (iii) failure by the Company or certain of its subsidiaries, if any, to comply with certain of their respective obligations, covenants or agreements contained in the 2028 Notes or the 2028 Notes Indenture, subject to certain notice and grace periods; (iv) failure by the Company or any of its restricted subsidiaries to pay indebtedness within any applicable grace period or the acceleration of any such indebtedness if the total amount of such indebtedness exceeds $35.0 million; (v) failure by the Company or any of its restricted subsidiaries that is a Significant Subsidiary (as defined in the 2028 Notes Indenture) to pay final non-appealable judgments aggregating in excess of $35.0 million, which judgments are not paid, discharged or stayed for a period of 60 days; (vi) except as permitted by the 2028 Notes Indenture, any guarantee of the 2028 Notes is held in any judicial proceeding to be unenforceable or invalid, or ceases for any reason to be in full force and effect, or is denied or disaffirmed by a Guarantor (as defined in the 2028 Notes Indenture); and (vii) certain events of bankruptcy or insolvency described in the 2028 Notes Indenture with respect to the Company and its restricted subsidiaries that are Significant Subsidiaries.

Second Lien Notes due 2023

During February 2021, the Company completed a cash tender offer pursuant to which it redeemed and retired $272.1 million in aggregate principal amount of the Second Lien Notes. Immediately thereafter, there was $15.7 million in aggregate principal amount of Second Lien Notes remaining outstanding. In May 2021, the Company redeemed and retired the remaining $15.7 million in aggregate principal amount of the Second Lien Notes, and as a result the Second Lien Notes have been retired in full.

Unsecured VEN Bakken Note

In January 2021, the Company repaid $65.0 million in aggregate principal amount under the Unsecured VEN Bakken Note, which was a scheduled repayment thereunder. In February 2021, the Company used a portion of the proceeds from the 2028 Notes to repay the remaining $65.0 million in aggregate principal amount outstanding under the Unsecured VEN Bakken Note, and as a result the note has been retired in full.

NOTE 5 COMMON AND PREFERRED STOCK

Common Stock

On September 18, 2020, the Company effected a 1-for-10 reverse stock split of the Company's issued and outstanding shares of common stock (the "Reverse Stock Split"). The Company's common stock began trading on a split-adjusted basis when the market opened on September 21, 2020. As a result of the Reverse Stock Split, every ten shares of the Company's issued and outstanding common stock automatically converted into one share of common stock, without any change in the par value per share. A total of 44,663,990 shares of common stock were issued and outstanding immediately after the Reverse Stock Split became effective on September 18, 2020. No fractional shares were outstanding following the Reverse Stock Split.

In connection with the Reverse Stock Split, the number of authorized shares of the Company's common stock was reduced to135,000,000 shares of common stock, par value $0.001 per share. As of June 30, 2021, the Company had 66,164,399 shares of common stock issued and outstanding.

In May 2021, the Company's Board of Directors declared a cash dividend on the Company's common stock in the amount of $0.03 per share. The dividend is payable on July 30, 2021 to stockholders of record as of the close of business on June 30, 2021.

Preferred Stock

The Company is authorized to issue up to 5,000,000 shares of preferred stock, par value $0.001 per share, with such designations, voting and other rights and preferences as may be determined from time to time by the Board of Directors. As of June 30, 2021, the Company had 2,218,732 shares of preferred stock issued and outstanding, all of which were shares of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock (the "Series A Preferred Stock").

The terms of the Series A Preferred Stock are set forth in the Certificate of Designations for the Series A Preferred Stock (the "Certificate of Designations"), as originally filed with the Delaware Secretary of State on November 22, 2019, and as amended thereafter. The Series A Preferred Stock ranks senior to the Company's common stock with respect to the payment of dividends and distribution of assets upon liquidation, dissolution or winding-up. Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by the board of directors of the Company, cumulative dividends in cash, at a rate of 6.500% per annum on the sum of (i) the $100 liquidation preference per share of Series A Preferred Stock (the "Liquidation Preference") and (ii) all accumulated and unpaid dividends (if any), payable semi-annually in arrears on May 15 and November 15 of each year, commencing on May 15, 2020. On May 15, 2021, the Company paid a dividend in the amount of $9.9163 per share to the holders of record of the Series A Preferred Stock as of May 1, 2021. This dividend, which totaled $22.0 million in the aggregate, was inclusive of all accrued and unpaid dividends from the original issue date of the Series A Preferred Stock. As of June 30, 2021, there were $1.8 million of undeclared accumulated dividends on the Series A Preferred Stock.

The Reverse Stock Split did not affect the number of authorized or issued and outstanding shares of the Company's preferred stock, nor the liquidation per share preference. As a result of the Reverse Stock Split and per the terms of the Certificate of Designations, the conversion rate for the Company's outstanding Series A Preferred Stock was automatically and proportionately decreased. The effect of the Reverse Stock Split resulted in the Company recalculating its historical, basic and diluted EPS to reflect the 1-for-10 reverse stock split, effective September 18, 2020.

The Series A Preferred Stock is convertible at the holders' option (an "Optional Conversion") into common stock at a conversion rate set forth in the Certificate of Designations, subject to customary adjustments as provided for therein. As of June 30, 2021, the conversion rate was 4.363 shares of common stock for each share of Series A Preferred Stock (which is equivalent to a conversion price of $22.92). Holders may be entitled to additional shares of common stock or cash in connection with a conversion that occurs in connection with a Fundamental Change (as defined in the Certificate of Designations). The Series A Preferred Stock is convertible at the Company's option (a "Mandatory Conversion") if the closing sale price of the Company's common stock equals or exceeds 145% of the conversion price for at least 20 trading days (whether or not consecutive) in a period of 30 consecutive trading days. A Mandatory Conversion would also entitle the holder to a cash payment equal to eight semi-annual dividend payments, less an amount equal to all cash dividend payments made in respect of such holder's shares of Series A Preferred Stock prior to such Mandatory Conversion. The occurrence of any Optional Conversion or Mandatory Conversion is subject to various terms and limitations set forth in the Certificate of Designations.

The Certificate of Designations also sets forth additional information relating to the payment of dividends, voting, conversion rights, consent rights, liquidation rights, the ranking of the Series A Preferred Stock in comparison with the Company's other securities, and other matters.

2021 Activity

Common Stock

On February 9, 2021, the Company closed an underwritten public offering of14,375,000 shares of its common stock at a price to the public of $9.75 per share. This offering resulted in net proceeds of approximately $132.9 million, after deducting underwriting discounts and commissions and estimated offering expenses.

On June 21, 2021, the Company closed an underwritten public offering of5,750,000 shares of its common stock at a price to the public of $17.50 per share. This offering resulted in net proceeds of approximately $95.3 million, after deducting underwriting discounts and commissions and estimated offering expenses.

During the six months ended June 30, 2021,60,611 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 $0.8 million, which is based on the market prices on the dates the shares were surrendered.

During the six months ended June 30, 2021, the Company issued21,977 shares of common stock to satisfy contingent consideration owed in connection with a prior acquisition of oil and gas properties.

Stock Repurchase Program

In May 2011, the Company's board of directors approved a stock repurchase program to acquire up to $150.0 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, 2021 and June 30, 2020, respectively, the Company didnot 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. All repurchased shares are now included in the Company's pool of authorized but unissued shares.

NOTE 6 STOCK-BASED COMPENSATION

The Company maintains its 2018 Equity Incentive Plan (the "2018 Plan"), which replaced the Company's prior 2013 Incentive Plan (the "2013 Plan"), for making equity-based awards to employees, directors and other eligible persons. No future awards will be made under the 2013 Plan. The 2013 Plan continues to govern awards that were made thereunder, which remain in effect pursuant to their terms. As of June 30, 2021, there were 738,798 shares available for future awards under the 2018 Plan.

In connection with the Reverse Stock Split (see Note 5), the Company reduced the number of shares of common stock available for issuance under the Company's equity incentive plans in proportion to the Reverse Stock Split ratio of 1-for-10. The Reverse Stock Split also reduced the number of shares of common stock issuable upon the vesting of its RSAs in proportion to the Reverse Stock Split ratio of 1-for-10 and caused a proportionate increase in share-based performance criteria applicable to such awards. The Reverse Stock Split has no impact on Net Income (Loss) or total Stockholders' Equity and for the three months ended June 30, 2021 and 2020.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity instruments and are included in the "General and administrative expenses" line item in the unaudited statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in the "Oil and natural gas properties" line item in the unaudited balance sheets.

The 2018 Plan and 2013 Plan award types are summarized as follows:

Restricted Stock Awards

The Company issues restricted stock awards ("RSAs") subject to various vesting conditions as compensation to executive officers, employees and directors of the Company. RSAs issued to employees and executive officers generally vest over three years, provided that any performance and/or market conditions are also met. RSAs issued to directors generally vest over one year, provided that any performance and/or market conditions are also met. For RSAs subject to service and/or performance vesting conditions, the grant-date fair value is established based on the closing price of the Company's common stock on such date. Stock-based compensation expense for awards subject to only service conditions is recognized on a straight-line basis over the service period. Stock-based compensation expense for awards with both service and performance conditions is recognized on a graded basis only if it is probable that the performance condition will be achieved. The Company accounts for forfeitures of awards granted under these plans as they occur in determining stock-based compensation expense.

For awards subject to a market condition, the grant-date fair value is estimated using a Monte Carlo valuation model. The Company recognizes stock-based compensation expense for awards subject to market-based vesting conditions regardless of whether it becomes probable that these conditions will be achieved or not, and stock-based compensation expense for any such awards is not reversed if vesting does not actually occur. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility is calculated based on the historical volatility and implied volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period.

The following table reflects the outstanding RSAs and activity related thereto for the six months ended June 30, 2021:

	Service-based Awards		Service and Performance-based Awards		Service and Market-based Awards		Service, Performance, and Market-based Awards	
	Number of Shares	**Weighted-average Grant Date Fair Value**	**Number of Shares**	**Weighted-average Grant Date Fair Value**	**Number of Shares**	**Weighted-average Grant Date Fair Value**	**Number of Shares**	**Weighted-average Grant Date Fair Value**
Outstanding at December 31, 2020	268,602	$ 10.44	16,250	$ 27.00	5,245	$ 16.70	39,200	$ 9.80
Shares granted	169,254	11.85	—	—	—	—	—	—
Shares forfeited	—	—	—	—	—	—	—	—
Shares vested	(121,543)	11.11	(16,250)	27.00	(5,245)	16.70	(19,600)	9.80
Outstanding at June 30, 2021	316,313	$ 10.93	—	$ —	—	$ —	19,600	$ 9.80

At June 30, 2021, there was $3.3 million of total unrecognized compensation expense related to unvested RSAs. That cost is expected to be recognized over a weighted average period of 1.05 years. For the six months ended June 30, 2021 and 2020, the total fair value of the Company's restricted stock awards vested was $1.8 million and $1.9 million, respectively.

NOTE 7 RELATED PARTY TRANSACTIONS

The Company's Audit Committee is responsible for approving all transactions involving related parties.

NOTE 8 COMMITMENTS & CONTINGENCIES

Litigation

The Company is engaged in various 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 Company's 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 $4.2 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 $4.2

million in accounts receivable is included in "Other Noncurrent Assets, Net" in the condensed balance sheets. The Company fully maintains the validity of its interests in the crude oil and natural gas leases.

NOTE 9 INCOME TAXES

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The provision for income taxes for the three and six months ended June 30, 2021 and 2020 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income due to the recognition of a full valuation allowance during both the three and six months ended June 30, 2021 and 2020, respectively.

In assessing the realizability of deferred tax assets ("DTAs"), management considers whether it is more likely than not that some portion, or all, of the Company's DTAs will not be realized. In making such determination, the Company considers all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the projected future income and results of operations, and (iv) its ability to use tax planning strategies. If the Company concludes that it is more likely than not that some portion, or all, of its DTAs will not be realized, the tax asset is reduced by a valuation allowance. The Company assesses the appropriateness of its valuation allowance on a quarterly basis. At June 30, 2021 and December 31, 2020, the Company maintains a full valuation allowance on its net DTAs.

NOTE 10 FAIR VALUE

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

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

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

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

Financial Assets and Liabilities

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2021 and December 31, 2020:

(In thousands)	Fair Value Measurements at June 30, 2021 Using Quoted Prices In Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Assets	$ —	$ 518	$ —
Commodity Derivatives – Noncurrent Assets	—	32	—
Commodity Derivatives – Current Liabilities	—	(140,136)	—
Commodity Derivatives – Noncurrent Liabilities	—	(127,421)	—
Interest Rate Derivatives – Current Liabilities	—	(558)	—
Interest Rate Derivatives – Noncurrent Liabilities	—	(105)	—
Total	$ —	$ (267,670)	$ —

(In thousands)	Fair Value Measurements at December 31, 2020 Using Quoted Prices In Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Assets	$ —	$ 51,290	$ —
Commodity Derivatives – Current Liabilities	—	(2,504)	—
Commodity Derivatives – Noncurrent Assets	—	111	—
Commodity Derivatives – Noncurrent Liabilities	—	(14,214)	—
Interest Rate Derivatives – Current Liabilities	—	(574)	—
Interest Rate Derivatives – Noncurrent Liabilities	—	(445)	—
Total	$ —	$ 33,664	$ —

Commodity Derivatives. The Level 2 instruments presented in the tables above consist of commodity derivative instruments (see Note 11). The fair value of the Company's commodity derivative 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 commodity derivative contracts is reflected in the condensed balance sheet. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

Interest Rate Derivatives. The Level 2 instruments presented in the tables above consist of interest rate derivative instruments (see Note 11). The fair value of the Company's interest rate derivative instruments is determined based upon contracted notional amounts, active market-quoted LIBOR yield curves, and time to maturity, among other things. Counterparty statements are utilized to determine the value of the interest rate 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 interest rate derivative contracts is reflected in 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 carrying amounts of cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments.

Long-term debt is not presented at fair value in the balance sheets, as it is recorded at carrying value, net of unamortized debt issuance costs and unamortized premium or discount (see Note 4). The fair value of the Company's 2028 Notes was $595.4

million at June 30, 2021. The fair value of the Company's 2028 Notes are based on active market quotes, which represent Level 1 inputs.

There is no active market for the Revolving Credit Facility. The recorded value of the Revolving Credit Facility approximates its fair value because of its floating rate structure based on the LIBOR spread, secured interest, and the Company's borrowing base utilization. The fair value measurement for the Revolving Credit Facility represents a Level 2 input.

Non-Financial Assets and Liabilities

The Company estimates asset retirement obligations pursuant to the provisions of 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 natural 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 and acquired during the six months ended June 30, 2021 were approximately $8.0 million.

The Company issued common stock warrants in the Company as a part of the Reliance Acquisition as purchase consideration. The common stock warrants issued were to purchase 3,250,000 shares of the Company's common stock at an exercise price equal to$14.00 per share (subject to certain adjustments), which are generally exercisable from June 30, 2021 until April 1, 2028. The fair value of the common stock warrants consideration was determined by utilizing an Option Pricing Model. These non-recurring fair value measurements are primarily determined using inputs observable or can be corroborated by observable market data (Level 2 inputs).

The Company accounts for acquisitions of oil and natural gas properties under the acquisition method of accounting. Accordingly, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair value of oil and natural gas properties. The fair value of these properties is measured using a discounted cash flow model that converts future cash flows to a single discounted amount. These assumptions represent Level 3 inputs under the fair value hierarchy. See Note 3 for additional discussion of the Company's acquisitions of oil and natural gas properties during the six months ended June 30, 2021 and discussion of the significant inputs to the valuations.

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, 2021.

NOTE 11 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes commodity price swaps, basis swaps, swaptions and call options to (i) reduce the effects of volatility in price changes on the crude oil and natural gas 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. In addition, from time to time the Company utilizes interest rate swaps to mitigate exposure to changes in interest rates on the Company's variable-rate indebtedness.

All derivative instruments are recorded in 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 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 Company has master netting agreements on individual derivative instruments with certain counterparties and therefore the current asset and liability are netted in the balance sheet and the non-current asset and liability are netted in the balance sheet for contracts with these counterparties.

Commodity Derivative Instruments

The following table presents settlements on commodity derivative instruments and unsettled gains and losses on open commodity derivative instruments for the periods presented which is recorded in the revenue section of our condensed financial statements:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	**2021**	**2020**	**2021**	**2020**
Cash Received (Paid) on Settled Derivatives	$ (27,855)	$ 77,439	$ (35,152)	$ 108,944
Non-Cash Mark-to-Market Gain (Loss) on Derivatives	(173,057)	(150,077)	(301,695)	194,999
Gain (Loss) on Commodity Derivatives, Net	$ (200,912)	$ (72,638)	$ (336,847)	$ 303,943

The following table summarizes open commodity derivative positions as of June 30, 2021, for commodity derivatives that were entered into through June 30, 2021, for the settlement period presented**:**

	2021	2022	2023	2024
Oil:				
WTI NYMEX - Swaps:				
Volume (Bbl)	4,397,966	6,359,355	677,250	—
Weighted-Average Price ($/Bbl)	$ 54.45	$ 54.89	$ 58.66	$ —
WTI NYMEX - Swaptions[(1)]:				
Volume (Bbl)	—	766,125	3,691,000	—
Weighted-Average Price ($/Bbl)	$ —	$ 55.15	$ 50.31	$ —
Bakken Crude UHC to WTI NYMEX - Basis Swaps:				
Volume (Bbl)	2,631,870	—	—	—
Weighted-Average Price ($/Bbl)	$ (2.47)	$ —	$ —	$ —
WTI NYMEX - Call Options[(1)]:				
Volume (Bbl)	—	—	365,000	3,264,210
Weighted-Average Price ($/Bbl)	$ —	$ —	$ 55.00	$ 57.22
Natural Gas:				
Henry Hub NYMEX - Swaps:				
Volume (MMBtu)	14,728,136	13,897,291	—	—
Weighted-Average Price ($/MMBtu)	$ 2.82	$ 2.94	$ —	$ —
Waha Inside FERC to Henry Hub - Basis Swaps:				
Volume (MMBtu)	191,000	365,000	—	—
Weighted-Average Differential ($/MMBtu)	$ (0.11)	$ (0.26)	$ —	$ —
Columbia/TCO-POOL - Basis Swaps:				
Volume (MMBtu)	1,137,845	1,067,187	—	—
Weighted-Average Differential ($/MMBtu)	$ (0.45)	$ (0.43)	$ —	$ —
Dominion - App - Basis Swaps:				
Volume (MMBtu)	379,281	355,729	—	—
Weighted-Average Differential ($/MMBtu)	$ (0.65)	$ (0.64)	$ —	$ —
NE - TETCO M2 - Basis Swaps:				
Volume (MMBtu)	4,505,901	5,639,374	1,350,000	—
Weighted-Average Differential ($/MMBtu)	$ (0.76)	$ (0.78)	$ (0.83)	$ —
NGL:				
TET-OPIS - Swaps:				
Volume (Bbl)	61,500	—	—	—
Weighted-Average Price ($/Bbl)	$ 34.34	$ —	$ —	$ —

(1) Swaptions are crude oil derivative contracts that give counterparties the option to extend certain derivative contracts for additional periods. Call Options are crude oil derivative contracts sold by the Company that give counterparties the option to exercise certain derivative contracts. The volumes and prices reflected as Swaptions and Call Options in this table will only be effective if the options are exercised by the applicable counterparties.

Interest Rate Derivative Instruments

The Company uses interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. As of June 30, 2021, the Company had interest rate swaps with a total notional amount of $200.0 million. The settlement of these derivative instruments is recognized as a component of interest expense in the condensed statements of operations. The mark-to-market component of these derivative instruments is recognized in gain (loss) on unsettled interest rate derivatives, net in the condensed statements of operations.

Other Information Regarding Derivative Instruments

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at June 30, 2021 and December 31, 2020, 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 Commodity	Balance Sheet Location	June 30, 2021 Estimated Fair Value	December 31, 2020 Estimated Fair Value
Derivative Assets:		(In thousands)	
Commodity Price Swap Contracts	Current Assets	$ 24	$ 52,702
Commodity Basis Swap Contracts	Current Assets	1,977	37
Commodity Price Swaptions Contracts	Current Assets	1,110	—
Commodity Price Swap Contracts	Noncurrent Assets	57	3,479
Commodity Basis Swap Contracts	Noncurrent Assets	342	—
Commodity Price Swaptions Contracts	Noncurrent Assets	1,127	—
Interest Rate Swap Contracts	Noncurrent Assets	5	—
Total Derivative Assets		$ 4,642	$ 56,218
Derivative Liabilities:			
Commodity Price Swap Contracts	Current Liabilities	$ (130,278)	$ (3,434)
Commodity Basis Swap Contracts	Current Liabilities	(6,174)	(519)
Commodity Price Swaptions Contracts	Current Liabilities	(6,278)	—
Interest Rate Swap Contracts	Current Liabilities	(558)	(574)
Commodity Price Swap Contracts	Noncurrent Liabilities	(32,345)	(399)
Interest Rate Swap Contracts	Noncurrent Liabilities	(105)	(445)
Commodity Basis Swap Contracts	Noncurrent Liabilities	(342)	—
Commodity Price Call Option Contracts	Noncurrent Liabilities	(36,206)	—
Commodity Price Swaptions Contracts	Noncurrent Liabilities	(60,028)	(17,184)
Total Derivative Liabilities		$ (272,312)	$ (22,554)

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 in the balance sheet. The tables presented below provide reconciliation between the gross assets and liabilities and the amounts reflected in the balance sheet. The amounts presented exclude derivative settlement receivables and payables as of the balance sheet dates.

(In thousands)	Estimated Fair Value at June 30, 2021 Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets (Liabilities) Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 3,111	$ (2,593)	$ 518
Non-Current Assets	1,531	(1,499)	32
Total Derivative Assets	$ 4,642	$ (4,092)	$ 550
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (143,287)	$ 2,593	$ (140,694)
Non-Current Liabilities	(129,025)	1,499	(127,526)
Total Derivative Liabilities	$ (272,312)	$ 4,092	$ (268,220)

(In thousands)	Estimated Fair Value at December 31, 2020 Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 52,739	$ (1,449)	$ 51,290
Non-Current Assets	3,479	$ (3,369)	111
Total Derivative Assets	$ 56,218	$ (4,817)	$ 51,401
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (4,527)	$ 1,449	$ (3,078)
Non-Current Liabilities	(18,028)	$ 3,369	(14,659)
Total Derivative Liabilities	$ (22,554)	$ 4,817	$ (17,737)

All of the Company's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements ("ISDAs") entered into with parties 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, 2021. 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, 2021 and December 31, 2020.

NOTE 12 SUBSEQUENT EVENT

Permian Basin Acquisition

On May 28, 2021, the Company entered into a purchase and sale agreement ("PSA"), effective as of April 1, 2021, to acquire oil and gas properties in the Permian Basin. On August 2, 2021, the Company closed on the acquisition for total estimated consideration of $105.6 million in cash (which includes a $9.4 million deposit previously paid by the Company upon the execution of the PSA and held in escrow in accordance with the terms of the PSA). The Company has considered the disclosure requirements of ASC 805-10-50-2 and ASC 805-10-50-4 but has not included the required disclosures due to the timing of the transaction relative to the date of the report containing these condensed financial statements.

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

Cautionary Statement Concerning Forward-Looking Statements

This report 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, indebtedness covenant compliance, capital expenditures, production, cash flow, borrowing base under our revolving credit facility, and impairment 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," "continue," "anticipate," "target," "could," "plan," "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 production 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 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 current properties and properties pending acquisition, the effects of the COVID-19 pandemic and related economic slowdown, infrastructure constraints and related factors affecting our properties, ongoing legal disputes over and potential shutdown of the Dakota Access Pipeline, our ability to acquire additional development opportunities, changes in our reserves estimates or the value thereof, general economic or industry conditions, nationally and/or in the communities in which we conduct business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, our ability to consummate any pending acquisition transactions, other risks and uncertainties related to the closing of pending acquisition transactions, our ability to raise or access capital, changes in accounting principles, policies or guidelines, financial or political instability, health-related epidemics, 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 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, 2020, 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. We do not undertake, and specifically disclaim, 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 unaudited Condensed Financial Statements and accompanying Notes to Condensed Financial Statements appearing elsewhere in this report.

Overview

Our primary strategy is to invest in non-operated minority working and mineral interests in oil and gas properties, with a core area of focus in the premier basins within the United States. Using this strategy, we had participated in 7,173 gross (588.6 net) producing wells as of June 30, 2021. As of June 30, 2021, we had leased approximately 244,449 net acres, of which approximately 87% were developed and substantially all were located in either the Williston, Appalachian or Permian Basins in the United States.

On April 1, 2021, we completed our acquisition (the "Reliance Acquisition") of producing natural gas properties and related assets consisting of approximately 95.3 net producing wells, 24.9 net wells in progress, and approximately 61,712 net acres, all of which is located in the Appalachian Basin in Pennsylvania. We paid a combination of cash and common stock warrant consideration, which we estimate had a combined fair value of $139.7 million. We estimate that this acquisition contributed production of approximately 10,593 Boe per day in the second quarter of 2021.

Our average daily production in the second quarter of 2021 was approximately 54,623 Boe per day, of which approximately 61% was oil. This was a 42% increase in production compared to the first quarter of 2021, primarily due to production attributable to the Reliance Acquisition, as well as the return of shut-in and curtailed production and new wells added to production. During the three months ended June 30, 2021, we added 10.5 net wells to production, in addition to the wells added at closing from the Reliance Acquisition. This compared to 6.7 net wells added to production in the first quarter of 2021.

Impacts of COVID-19 Pandemic and Economic Environment

The novel coronavirus disease (COVID-19) and efforts to mitigate the spread of the disease have created unprecedented challenges for our industry, including a drastic decline in demand for crude oil. In addition, in March 2020, members of OPEC failed to agree on production levels which led to a substantial decrease in oil prices and an increasingly volatile market. The oil price war ended in April 2020, with a deal to cut global petroleum output but did not go far enough to offset the impact of COVID-19 on demand. As a result of lower demand caused by the COVID-19 pandemic and the oversupply of crude oil, spot and future prices of crude oil fell to historic lows during the second quarter of 2020 and remained depressed through much of 2020. Operators in the Williston Basin responded by significantly decreasing drilling and completion activity, and by shutting in or curtailing production from a significant number of producing wells. As a result of these factors, we reduced our 2020 developmental capital spending to $162.8 million, a reduction of 56% compared to our developmental capital expenditures in 2019. Conditions have improved with the recovery of commodity prices in late 2020 and the first half of 2021, but operators' decisions on these matters are evolving rapidly, and it remains difficult to predict the future effects on our Company and its business.

Reverse Stock Split

On September 18, 2020, we effected a 1-for-10 reverse stock split of the Company's issued and outstanding shares of common stock (the "Reverse Stock Split"). References to numbers of shares of common stock and per share data have been adjusted to reflect the Reverse Stock Split on a retroactive basis. See Note 5 to our condensed financial statements for further information.

Sources 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.

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 substantially all of our acreage and wells in the Williston Basin and the Appalachian Basin subjects our operating results to factors specific to these regions. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, as well as infrastructure limitations, transportation capacity, regulatory matters and other factors that may specifically affect one or both of these regions.

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. Additional pipeline infrastructure has increased takeaway capacity in the Williston Basin which has improved wellhead values in the region, specifically the Dakota Access Pipeline ("DAPL") which has given the region low-cost transportation with access to Gulf Coast markets. However, DAPL is subject to ongoing litigation and regulatory review that could threaten its continued operation. During any period that DAPL is forced to shut down, we would expect our average oil price differential to increase, although it is difficult to predict with any precision what effect this would have.

The price at which our oil production is sold typically reflects a discount to the NYMEX benchmark price. The price at which our natural gas production is sold may reflect either a discount or premium to the NYMEX benchmark price. Thus, our operating results are also affected by changes in the price differentials between the applicable benchmark and the sales prices we receive for our production. Our oil price differential to the NYMEX benchmark price during the second quarter of 2021 was $5.46 per barrel, as compared to $10.60 per barrel in the second quarter of 2020. Our net realized gas price in the second quarter of 2021 was $3.57 per Mcf, representing 122% realization relative to average Henry Hub pricing, compared to a net realized gas price of $(2.67) per Mcf in the second quarter of 2020. Fluctuations in our price differentials and realizations are due to several factors such as gathering and transportation costs, takeaway capacity relative to production levels, regional storage capacity, and seasonal refinery maintenance temporarily depressing demand.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells can vary significantly, driven in part by volatility in commodity prices that can substantially impact the level of drilling activity. During the first six months of 2021, the weighted average gross authorization for expenditure (or AFE) cost for wells we elected to participate in was $6.6 million, compared to $7.6 million for the wells we elected to participate in during 2020.

Market Conditions

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Because our oil and gas revenues are heavily weighted toward oil, 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 production from properties within the United States, the production quota set by OPEC, and the strength of the U.S. dollar can adversely impact oil prices. 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, NGLs and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the three and six months ended June 30, 2021 and 2020.

	Three Months Ended June 30,	
	2021	2020
Average NYMEX Prices[1]		
Natural Gas (per Mcf)	$ 2.92	$ 1.70
Oil (per Bbl)	$ 66.19	$ 27.95

	Six Months Ended June 30,	
	2021	2020
Average NYMEX Prices[1]		
Natural Gas (per Mcf)	$ 3.14	$ 1.80
Oil (per Bbl)	$ 62.22	$ 36.69

(1) Based on average NYMEX closing prices.

For the three months ended June 30, 2021, the average NYMEX pricing was $66.19 per barrel of oil, or 137% higher than the average NYMEX price per barrel for the comparable period in 2020. Our realized oil price after reflecting settled commodity derivatives was 17% lower in the second quarter of 2021 than in the second quarter of 2020 due to the higher average NYMEX price per barrel and a lower oil price differential, partially offset by the loss on settled oil derivatives in the second quarter of 2021 versus a gain on settled oil derivatives in the second quarter of 2020.

For the three months ended June 30, 2021, the average NYMEX pricing for natural gas was $2.92 per Mcf, or 72% higher than in the comparable period in 2020. Our realized natural gas price after reflecting settled commodity derivatives was 237% higher in the second quarter of 2021 than in the second quarter of 2020 due to the higher average NYMEX natural gas price. In addition, we saw a higher uplift from increased pricing on NGLs. However, these factors were partially offset by the loss on settled natural gas derivatives in the second quarter of 2021 versus the second quarter of 2020.

As of June 30, 2021, we had a total volume on open crude oil price swaps of 11.4 million barrels at a weighted average price of approximately $54.94 per barrel. As of June 30, 2021, we had a total volume on open natural gas price swaps of 28.6 MMbtu at a weighted average price of approximately $2.88 per MMbtu. See Note 11 to the condensed financial statements.

Principal Components of Our Cost Structure

- *Commodity price differentials*. The price differential between our well head price for oil and the NYMEX WTI benchmark price is primarily driven by the cost to transport oil via train, pipeline or truck to refineries. The price differential between our well head price for natural gas and NGLs and the NYMEX Henry Hub benchmark price is primarily driven by gathering and transportation costs.

- *Gain (loss) on commodity derivatives, net.* We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the prices of oil and gas. Gain (loss) on commodity derivatives, net is comprised of (i) cash gains and losses we recognize on settled commodity derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on commodity 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 accretion.* Depreciation, depletion, amortization and accretion 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. Accretion expense relates to the passage of time of our asset retirement obligations.

- *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 unproven 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.

Results of Operations for the Three Months Ended June 30, 2021 and June 30, 2020

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

	Three Months Ended June 30,		
	2021	2020	% Change
Net Production:			
Oil (Bbl)	3,034,442	1,659,293	83 %
Natural Gas and NGLs (Mcf)	11,617,308	3,041,418	282 %
Total (Boe)	4,970,660	2,166,196	129 %
Net Sales (in thousands):			
Oil Sales	$ 184,269	$ 28,784	540 %
Natural Gas and NGL Sales	41,447	(8,120)	
Gain (Loss) on Settled Commodity Derivatives	(27,855)	77,439	
Gain (Loss) on Unsettled Commodity Derivatives	(173,057)	(150,077)	
Other Revenue	—	3	
Total Revenues	24,805	(51,971)	
Average Sales Prices:			
Oil (per Bbl)	$ 60.73	$ 17.35	250 %
Effect of Gain (Loss) on Settled Oil Derivatives on Average Price (per Bbl)	(8.16)	46.19	
Oil Net of Settled Oil Derivatives (per Bbl)	52.57	63.54	(17) %
Natural Gas and NGLs (per Mcf)	3.57	(2.67)	
Effect of Gain (Loss) on Settled Natural Gas Derivatives on Average Price (per Mcf)	(0.27)	0.26	
Natural Gas and NGLs Net of Settled Natural Gas Derivatives (per Mcf)	3.30	(2.41)	
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives	45.41	9.54	376 %
Effect of Gain (Loss) on Settled Commodity Derivatives on Average Price (per Boe)	(5.60)	35.75	
Realized Price on a Boe Basis Including Settled Commodity Derivatives	39.81	45.29	(12) %
Operating Expenses (in thousands):			
Production Expenses	$ 42,699	$ 26,638	60 %
Production Taxes	18,514	1,917	866 %
General and Administrative Expenses	7,604	4,709	61 %
Depletion, Depreciation, Amortization and Accretion	30,908	36,756	(16) %
Costs and Expenses (per Boe):			
Production Expenses	$ 8.59	$ 12.30	(30) %
Production Taxes	3.72	0.89	318 %
General and Administrative Expenses	1.53	2.17	(29) %
Depletion, Depreciation, Amortization and Accretion	6.22	16.97	(63) %
Net Producing Wells at Period End	588.6	466.0	26 %

Oil and Natural Gas Sales

In the second quarter of 2021, our oil, natural gas and NGL sales, excluding the effect of settled commodity derivatives, was $225.7 million as compared to $20.7 million in the second quarter of 2020, driven by a 376% increase in realized prices, excluding the effect of settled commodity derivatives, and a 129% increase in production. The higher average realized price in the second quarter of 2021 as compared to the same period in 2020 was driven by higher average NYMEX oil prices and a lower oil price differential. Oil price differential during the second quarter of 2021 was $5.46 per barrel, as compared to $10.60 per barrel in the second quarter of 2020. The higher average realized price in the second quarter of 2021 as compared to the same period in 2020 was also driven by a $6.24 increase in realized natural gas and NGL prices, excluding the effect of settled commodity derivatives, in the second quarter of 2021 compared to the same period of 2020. See “Market Conditions” 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 production from existing wells. Our acquisition program is a significant driver of our net well additions in certain years. Curtailments, shut-ins and reduced development activity during 2020, which had largely abated by the second quarter of 2021, as well as production added from the Reliance Acquisition, drove our 129% increase in production levels in the second quarter of 2021 compared to the same period in 2020. See “Impacts of COVID-19 Pandemic and Economic Environment” above.

Commodity Derivative Instruments

We enter into commodity derivative instruments to manage the price risk attributable to future oil and natural gas production. Our gain (loss) on commodity derivatives, net, was a loss of $200.9 million in the second quarter of 2021, compared to a loss of $72.6 million in the second quarter of 2020. Gain (loss) on commodity derivatives, net, is comprised of (i) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (ii) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

For the second quarter of 2021, we realized a loss on settled commodity derivatives of $27.9 million, compared to a $77.4 million gain in the second quarter of 2020. The decrease in settled derivatives was primarily due to a significant increase in the average NYMEX oil price in the second quarter of 2021 compared to the same period of 2020. During the second quarter of 2021, our derivative settlements included 2.2 million barrels of oil at an average settlement price of $56.38 per barrel. During the second quarter of 2020, our commodity derivative settlements included 2.6 million barrels of oil at an average settlement price of $57.84 per barrel. The average NYMEX oil price for the second quarter of 2021 was $66.19 compared to $27.95 for the second quarter of 2020. Our average realized price (including all commodity derivative cash settlements) in the second quarter of 2021 was $39.81 per Boe compared to $45.29 per Boe in the second quarter of 2020. The gain (loss) on settled derivatives decreased our average realized price per Boe by $5.60 in the second quarter of 2021 and increased our average realized price per Boe by $35.75 in the second quarter of 2020.

Unsettled commodity derivative gains and losses was a loss of $173.1 million in the second quarter of 2021, compared to a loss of $150.1 million in the second quarter of 2020. 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 commodity derivatives. Any gains on our unsettled commodity derivatives are expected to be offset by lower wellhead revenues in the future, while any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At June 30, 2021, all of our derivative contracts are recorded at their fair value, which was a net liability of $267.7 million, a decrease of $301.3 million from the $33.7 million net asset recorded as of December 31, 2020. The decrease at June 30, 2021 as compared to December 31, 2020 was primarily due to changes in forward oil prices relative to prices on our open oil derivative contracts since December 31, 2020. Our open oil derivative contracts are summarized in “Item 3. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Production Expenses

Production expenses were $42.7 million in the second quarter of 2021, compared to $26.6 million in the second quarter of 2020. On a per unit basis, production expenses decreased from $12.30 per Boe in the second quarter of 2020 to $8.59 per Boe in the second quarter of 2021 due in large part to a 129% increase in our production volumes, which increased the production base over which fixed costs are spread. On an absolute dollar basis, the increase in our production expenses in the second quarter of 2021, as compared to the second quarter of 2020, was primarily due to a 129% increase in production levels coupled with a 26% increase in the total number of net producing wells.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were $18.5 million in the second quarter of 2021 compared to $1.9 million in the second quarter of 2020. The increase is due to higher realized prices which increased our oil and natural gas sales in the second quarter of 2021 as compared to the second quarter of 2020. As a percentage of oil and natural gas sales, our production taxes were 8.2% and 9.3% in the second quarter of 2021 and 2020, respectively. The fluctuation in our average production tax rate from year to year is primarily due to changes in our oil sales as a percentage of our total oil and gas sales. Oil sales are taxed at a higher rate than natural gas sales.

General and Administrative Expenses

General and administrative expenses were $7.6 million in the second quarter of 2021 compared to $4.7 million in the second quarter of 2020. The increase was primarily due to $3.0 million in acquisition-related costs in connection with the Reliance Acquisition and a $0.3 million increase in professional fees, which was partially offset by $0.4 million reduction in compensation and insurance expense.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion (“DD&A”) was $30.9 million in the second quarter of 2021, compared to $36.8 million in the second quarter of 2020. Depletion expense, the largest component of DD&A, decreased by $6.0 million in the second quarter of 2021 compared to the second quarter of 2020. The aggregate decrease in depletion expense was driven by a 64% decrease in the depletion rate per Boe offset by a 129% increase in production levels. On a per unit basis, depletion expense was $6.11 per Boe in the second quarter of 2021 compared to $16.80 per Boe in the second quarter of 2020. The lower depletion rate per Boe was primarily driven by the decrease in our depletable base as a result of the impairment of oil and natural gas properties during 2020 and the closing of the Reliance Acquisition. Depreciation, amortization and accretion was $0.5 million and $0.4 million in the second quarter of 2021 and 2020, respectively. The following table summarizes DD&A expense per Boe for the second quarter of 2021 and 2020:

	Three Months Ended June 30,			
	2021	2020	$ Change	% Change
Depletion	$ 6.11	$ 16.80	$ (10.69)	(64) %
Depreciation, Amortization and Accretion	0.11	0.17	(0.06)	(35) %
Total DD&A Expense	$ 6.22	$ 16.97	$ (10.75)	(63) %

Interest Expense

Interest expense, net of capitalized interest, was $15.0 million in the second quarter of 2021 compared to $14.0 million in the second quarter of 2020. The increase in interest expense was primarily due to higher interest rates on the debt outstanding, offset by reduced debt levels in the second quarter of 2021 compared to the second quarter of 2020.

Loss on the Extinguishment of Debt

As a result of our refinancing transactions during the second quarter of 2021 (see Note 4 to our condensed financial statements), we recorded a loss on the extinguishment of debt of $0.5 million based on the differences between the reacquisition costs of retiring the applicable debt and the net carrying values thereof. As a result of a series of exchange transactions of our Second Lien Notes during the second quarter of 2020, we recorded a gain on the extinguishment of debt of $0.2 million based on the differences between the reacquisition costs of retiring the applicable debt and the net carrying values thereof.

Income Tax

During the second quarters of 2021 and 2020, no income tax expense (benefit) was recorded on the income (loss) before income taxes, due to the valuation allowance placed on our net deferred tax asset because of the uncertainty regarding its realization.

We intend to continue maintaining a full valuation allowance on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of these allowances. Release of any portion of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded. However, the exact timing and amount of the valuation allowance release are subject to change on the basis of the level of profitability that we are able to actually achieve. For further discussion of our valuation allowance, see Note 9 to our condensed financial statements.

Results of Operations for the Six Months Ended June 30, 2021 and June 30, 2020

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

	Six Months Ended June 30,		
	2021	2020	% Change
Net Production:			
Oil (Bbl)	5,664,620	4,797,673	18 %
Natural Gas and NGLs (Mcf)	16,581,571	8,090,538	105 %
Total (Boe)	8,428,215	6,146,096	37 %
Net Sales (in thousands):			
Oil Sales	$ 319,917	$ 145,116	120 %
Natural Gas and NGL Sales	63,131	5,744	999 %
Gain on Settled Commodity Derivatives	(35,152)	108,944	
Gain (Loss) on Unsettled Commodity Derivatives	(301,695)	194,999	
Other Revenue	1	11	
Total Revenues	46,202	454,815	(90) %
Average Sales Prices:			
Oil (per Bbl)	$ 56.48	$ 30.25	87 %
Effect of Gain on Settled Oil Derivatives on Average Price (per Bbl)	(5.45)	22.54	
Oil Net of Settled Oil Derivatives (per Bbl)	51.03	52.79	(3) %
Natural Gas and NGLs (per Mcf)	3.81	0.71	437 %
Effect of Gain on Settled Natural Gas Derivatives on Average Price (per Mcf)	(0.26)	0.10	
Natural Gas and NGLs Net of Settled Natural Gas Derivatives (per Mcf)	3.55	0.81	338 %
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives	45.45	24.55	85 %
Effect of Gain on Settled Commodity Derivatives on Average Price (per Boe)	(4.17)	17.72	
Realized Price on a Boe Basis Including All Realized Derivative Settlements	41.28	42.27	(2) %
Operating Expenses (in thousands):			
Production Expenses	$ 77,010	$ 63,974	20 %
Production Taxes	31,967	13,813	131 %
General and Administrative Expenses	14,388	9,580	50 %
Depletion, Depreciation, Amortization and Accretion	62,128	98,565	(37) %
Costs and Expenses (per Boe):			
Production Expenses	$ 9.14	$ 10.41	(12) %
Production Taxes	3.79	2.25	68 %
General and Administrative Expenses	1.71	1.56	10 %
Depletion, Depreciation, Amortization and Accretion	7.37	16.04	(54) %
Net Producing Wells at Period End	588.6	466.0	26 %

Oil and Natural Gas Sales

In the first six months of 2021, our oil, natural gas and NGL sales, excluding the effect of settled commodity derivatives, was $383.0 million as compared to $150.9 million in the first six months of 2020, driven by a 85% increase in realized prices, excluding the effect of settled commodity derivatives, and a 37% increase in production. The higher average realized price in the first six months of 2021 as compared to the same period in 2020 was partially driven by higher average NYMEX oil prices and a lower oil price differential. Oil price differential during the first six months of 2021 was $5.74 per barrel, as compared to $6.44 per barrel in the first six months of 2020. The higher average realized price in the second quarter of 2021 as compared to the same period in 2020 was also driven by a $3.10 increase in realized natural gas and NGL prices, excluding the effect of settled commodity derivatives, in the first six months of 2021 compared to the same period of 2020. See "Market Conditions" 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 production from existing wells. Our acquisition program is a significant driver of our net well additions in certain years. Curtailments, shut-ins and reduced development activity during 2020, which had largely abated by the second quarter of 2021, as well as production added from the Reliance Acquisition, drove our 37% increase in production levels in the first six months of 2021 compared to the same period in 2020. See "Impacts of COVID-19 Pandemic and Economic Environment" above.

Commodity Derivative Instruments

We enter into commodity derivative instruments to manage the price risk attributable to future oil and natural gas production. Our gain (loss) on commodity derivatives, net, was a loss of $336.8 million in the first six months of 2021, compared to a gain of $303.9 million in the first six months of 2020. Gain (loss) on commodity derivatives, net, is comprised of (i) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (ii) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

For the first six months of 2021, we realized a loss on settled commodity derivatives of $35.2 million, compared to a $108.9 million gain in the first six months of 2020. The decrease in settled derivatives was primarily due to a significant increase in the average NYMEX oil price in the first six months of quarter of 2021 compared to the same period of 2020. During the first six months of 2021, our derivative settlements included 4.4 million barrels of oil at an average settlement price of $56.02 per barrel. During the first six months of 2020, our commodity derivative settlements included 5.2 million barrels of oil at an average settlement price of $57.88 per barrel. The average NYMEX oil price for the first six months of 2021 was $62.22 compared to $36.69 for the first six months of 2020. Our average realized price (including all commodity derivative cash settlements) in the first six months of 2021 was $41.28 per Boe compared to $42.27 per Boe in the first six months of 2020. The gain (loss) on settled derivatives decreased our average realized price per Boe by $4.17 in the first six months of 2021 and increased our average realized price per Boe by $17.72 in the first six months of 2020.

Unsettled commodity derivative gains and losses was a loss of $301.7 million in the first six months of 2021, compared to a gain of $195.0 million in the first six months of 2020. 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 commodity derivatives. Any gains on our unsettled commodity derivatives are expected to be offset by lower wellhead revenues in the future, while any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At June 30, 2021, all of our derivative contracts are recorded at their fair value, which was a net liability of $267.7 million, a decrease of $301.3 million from the $33.7 million net asset recorded as of December 31, 2020. The decrease at June 30, 2021 as compared to December 31, 2020 was primarily due to changes in forward oil prices relative to prices on our open oil derivative contracts since December 31, 2020. Our open oil derivative contracts are summarized in "Item 3. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Production Expenses

Production expenses were $77.0 million in the first six months of 2021, compared to $64.0 million in the first six months of 2020. On a per unit basis, production expenses decreased from $10.41 per Boe in the first six months of 2020 to $9.14 per Boe in the first six months of 2021 due in large part to a 129% increase in our production volumes, which increased the production base over which fixed costs are spread. On an absolute dollar basis, the increase in our production expenses in the first six months of 2021, as compared to the first six months of 2020, was primarily due to a 37% increase in production levels and a 26% increase in the total number of net producing wells.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were $32.0 million in the first six months of 2021 compared to $13.8 million in the first six months of 2020. The increase is due to higher realized prices which increased our oil and natural gas sales in the first six months of 2021 as compared to the first six months of 2020. As a percentage of oil and natural gas sales, our production taxes were 8.3% and 9.2% in the first six months of 2021 and 2020, respectively. The fluctuation in our average production tax rate from year to year is primarily due to changes in our oil sales as a percentage of our total oil and gas sales. Oil sales are taxed at a higher rate than natural gas sales.

General and Administrative Expenses

General and administrative expenses were $14.4 million in the first six months of 2021 compared to $9.6 million in the first six months of 2020. The increase was primarily due to $5.5 million in acquisition-related costs in connection with the Reliance Acquisition, which was partially offset by a $0.6 million reduction in professional fees and compensation expense.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion (“DD&A”) was $62.1 million in the first six months of 2021, compared to $98.6 million in the first six months of 2020. Depletion expense, the largest component of DD&A, decreased by $36.7 million in the first six months of 2021 compared to the first six months of 2020. The aggregate decrease in depletion expense was driven by a 54% decrease in the depletion rate per Boe, offset by a 37% increase in production levels. On a per unit basis, depletion expense was $7.26 per Boe in the first six months of 2021 compared to $15.92 per Boe in the first six months of 2020. The lower depletion rate per Boe was primarily driven by the decrease in our depletable base as a result of the impairment of oil and natural gas properties during 2020 and the closing of the Reliance Acquisition. Depreciation, amortization and accretion was $1.0 million and $0.7 million for the first six months of 2021 and 2020, respectively. The following table summarizes DD&A expense per Boe for the first six months of 2021 and 2020:

	Six Months Ended June 30,			
	2021	**2020**	**$ Change**	**% Change**
Depletion	$ 7.26	$ 15.92	$ (8.66)	(54) %
Depreciation, Amortization and Accretion	0.11	0.12	(0.01)	(8) %
Total DD&A Expense	$ 7.37	$ 16.04	$ (8.67)	(54) %

Interest Expense

Interest expense, net of capitalized interest, was $28.5 million in the first six months of 2021 compared to $30.5 million in the first six months of 2020. The decrease in interest expense was primarily due to lower interest rates on the debt outstanding and reduced debt levels in the first six months of 2021 compared to the first six months of 2020.

Loss on the Extinguishment of Debt

As a result of our refinancing transactions during the first six months of 2021 (see Note 4 to our condensed financial statements), we recorded a loss on the extinguishment of debt of $13.1 million based on the differences between the reacquisition costs of retiring the applicable debt and the net carrying values thereof. As a result of a series of exchange transactions of our Second Lien Notes during the first six months of 2020, we recorded a loss on the extinguishment of debt of $5.3 million based on the differences between the reacquisition costs of retiring the applicable debt and the net carrying values thereof.

Income Tax

During the first six months of 2021 and 2020, no income tax expense (benefit) was recorded on the income (loss) before income taxes, due to the valuation allowance placed on our net deferred tax asset because of the uncertainty regarding its realization.

We intend to continue maintaining a full valuation allowance on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of these allowances. Release of any portion of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded. However, the exact timing and amount of the valuation allowance release are subject to change on the basis of the level of profitability that we are able to actually achieve. For further discussion of our valuation allowance, see Note 9 to our condensed financial statements.

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 equity and debt financings, credit facility borrowings, and cash settlements of commodity derivative instruments. Our primary uses of capital have been for the acquisition and development of our oil and natural gas properties. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

During the first half of 2021, we completed a number of significant financing transactions, including:

- completed a common stock offering in February 2021 with net proceeds of $132.9 million, which was primarily intended to finance the cash purchase price for the Reliance Acquisition that closed on April 1, 2021;
- completed another common stock offering in June 2021 with net proceeds of $95.3 million, which was primarily intended to finance the cash purchase price for oil and gas property acquisitions in the Permian Basin that primarily closed in the third quarter of 2021, but in the interim reduced the Company's outstanding indebtedness;
- issued $550.0 million in aggregate principal amount of new 8.125% senior unsecured notes due 2028 (the "2028 Notes"), priced at par, with estimated net proceeds of $538.4 million;
- fully repaid and retired all $130.0 million in principal amount of our 6.0% senior unsecured promissory note due 2022 (the "Unsecured VEN Bakken Note");
- fully redeemed and retired all $287.8 million in principal amount of our 8.500% senior secured second lien notes due 2023 (the "Second Lien Notes"); and
- reduced the amount of borrowings outstanding under our Revolving Credit Facility from $532.0 million as of December 31, 2020 to $263.0 million as of June 30, 2021.

See Note 4 to our condensed financial statements for further details regarding these financing transactions.

As of June 30, 2021, we had outstanding debt consisting of $263.0 million of borrowings under our Revolving Credit Facility and $550.0 million aggregate principal amount of 2028 Notes. We had total liquidity of $401.8 million as of June 30, 2021, consisting of $397.0 million of committed borrowing availability under the Revolving Credit Facility and $4.8 million of cash on hand.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility. Oil accounted for 61% and 77% of our total production volumes in the second quarter of 2021 and 2020, respectively. We seek to maintain a robust hedging program to mitigate volatility in commodity prices with respect to a portion of our expected production. For the three months ended June 30, 2021, we hedged approximately 70% of our production. For a summary as of June 30, 2021, of our open commodity swap contracts for future periods, see "Quantitative and Qualitative Disclosures about Market Risk" in Part I, Item 3 below.

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.

At June 30, 2021, we had a working capital deficit of $161.2 million, compared to $56.8 million at December 31, 2020. Current assets increased by $14.0 million and current liabilities increased by $118.4 million at June 30, 2021, compared to December 31, 2020. The increase in current assets is primarily due to a $60.1 million increase in our accounts receivable due to higher commodity prices, which was partially offset by a decrease in our derivative instruments of $50.8 million due to the change in fair value as a result of the commodity price environment. The change in current liabilities is due to a $137.6 million increase in our derivative instruments due to the change in fair value as a result of the commodity price environment, and a $36.4 million increase in our accounts payable and accrued liabilities due in part to increased completion activity levels on our properties, partially offset by a decrease in the current portion of our long-term debt of $65.0 million related to our Unsecured VEN Bakken Note.

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts, and by changes in working capital. Any interim cash needs are funded by cash on hand, cash flows from operations or borrowings under our Revolving Credit Facility. The Company typically enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated future oil and gas production for the next 12 to 24 months. Our cash flows for the six months ended June 30, 2021 and 2020 are presented below:

	Six Months Ended June 30,	
	2021	2020
	(in thousands, unaudited)	
Net Cash Provided by Operating Activities	$ 168,952	$ 202,239
Net Cash Used for Investing Activities	(213,541)	(190,514)
Net Cash Provided (Used) for Financing Activities	48,004	(25,955)
Net Change in Cash	$ 3,415	$ (14,229)

Cash Flows from Operating Activities

Net cash provided by operating activities for the six months ended June 30, 2021 was $169.0 million, compared to $202.2 million in the same period of the prior year. This decrease was due to changes in working capital and lower realized oil prices (including the effect of settled derivatives), which was partially offset by higher production volumes and lower interest costs. Net cash provided by operating activities is affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital and other items (as reflected in our statements of cash flows) in the six months ended June 30, 2021 was a deficit of $33.0 million compared to a surplus of $55.5 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, 2021 and 2020 were $213.5 million and $190.5 million, respectively. The increase in cash used in investing activities for the first six months of 2021 as compared to the same period of 2020 was attributable to a $14.4 million increase in our development and acquisition spending, which included the closing of our Reliance Acquisition. Additionally, the amount of capital expenditures included in accounts payable (and thus not included in cash flows from investing activities) was $101.0 million and $92.5 million at June 30, 2021 and 2020, 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, 2021, our capitalized costs incurred for oil and natural gas properties (e.g., drilling and completion costs, acquisitions, and other capital expenditures) amounted to $256.2 million, while the actual cash spend in this regard amounted to $204.1 million.

Development and acquisition activities are 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, 2021 and 2020 are summarized in the following table:

	Six Months Ended June 30,	
	2021	2020
	(in millions, unaudited)	
Drilling and Development Capital Expenditures	$ 72.6	$ 163.6
Acquisition of Oil and Natural Gas Properties	131.5	25.5
Other Capital Expenditures	0.7	0.6
Total	$ 204.8	$ 189.7

Cash Flows from Financing Activities

Net cash provided by financing activities was $48.0 million during the six months ended June 30, 2021, compared to net cash used for financing activities of $26.0 million during the six months ended June 30, 2020. For the six months ended June 30, 2021, cash provided by financing activities was primarily related to $537.6 million of net proceeds from our offering of 2028 Notes and $228.2 million of net proceeds from our offering of common stock, which was partially offset by $295.9 million in repurchases of Second Lien Notes, retirement of our Unsecured VEN Bakken Note of $130.0 million and $269.0 million of net repayments under our Revolving Credit Facility. For the six months ended June 30, 2020, cash used for financing activities was primarily related to $13.5 million in repurchases of Second Lien Notes and $12.0 million of net repayments under our Revolving Credit Facility.

Revolving Credit Facility

In November 2019, we entered into a revolving credit facility with Wells Fargo Bank, as administrative agent, and the lenders from time to time party thereto (the “Revolving Credit Facility”), which amended and restated our existing revolving credit facility that was entered into on October 5, 2018. The Revolving Credit Facility is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to our oil and gas properties. As of June 30, 2021, the Revolving Credit Facility had a borrowing base of $725.0 million and an elected commitment amount of $660.0 million, and we had $263.0 million in borrowings outstanding under the facility, leaving $397.0 million in available borrowing capacity. See Note 4 to our condensed financial statements for further details regarding the Revolving Credit Facility.

Unsecured Notes due 2028

As of June 30, 2021, we had $550.0 million in outstanding principal amount of our 8.125% senior unsecured notes due 2028. See Note 4 to our condensed financial statements for further details regarding the 2028 Notes.

Series A Preferred Stock

As of June 30, 2021, we had 2,218,732 outstanding shares of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock (the “Series A Preferred Stock”), having an aggregate liquidation preference of $221.9 million (excluding accumulated dividends). See Note 5 to our condensed financial statements for further details regarding the Series A Preferred Stock.

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.

Contractual Obligations and Commitments

Please see our disclosure of contractual obligations and commitments as of December 31, 2020, included in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2020.

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, 2020.

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, 2020.

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, 2020 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 we believe 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 commodity 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.

The following table summarizes our open crude oil swap contracts as of June 30, 2021, by fiscal quarter.

Settlement Period	Oil (Barrels)	Weighted Average Price ($)
Swaps-Crude Oil[(1)]		
2021:		
Q3	2,197,260	$ 54.63
Q4	2,200,706	54.26
2022:		
Q1	1,712,230	$ 54.89
Q2	1,572,025	55.35
Q3	1,600,800	54.88
Q4	1,474,300	54.42
2023:		
Q1	472,500	$ 57.92
Q2	204,750	60.38

(1) This table does not include volumes subject to swaptions and call options, which are crude oil derivative contracts we have entered into which may increase our swapped volumes at the option of our counterparties. See Note 11 to our condensed financial statements for further details regarding our commodity derivatives, including the swaptions and call options that are not included in the foregoing table.

The following table summarizes our open natural gas swap contracts as of June 30, 2021, by fiscal quarter.

Contract Period	Gas (MMBTU)	Weighted Average Price ($)
Swaps-Natural Gas		
2021:		
Q3	5,943,926	$ 2.82
Q4	8,784,210	2.82
2022:		
Q1	6,257,291	$ 3.07
Q2	2,730,000	2.84
Q3	2,760,000	2.84
Q4	2,150,000	2.80

See Note 11 to our condensed financial statements for further details regarding our commodity derivatives, including basis swap contracts for both crude oil and natural gas, which are not included in the foregoing tables.

Interest Rate Risk

Our long-term debt as of June 30, 2021 is comprised of borrowings that contain fixed and floating interest rates. The Second Lien Notes and our 2028 Notes bear cash interest at fixed rates. Our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement. At our option, borrowings under the Revolving Credit Facility bear interest at the base rate or LIBOR, plus an applicable margin. The base rate is a rate per annum equal to the greatest of: (i) the agent bank’s prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 100 to 200 basis points, and the applicable margin for LIBOR loans ranges from 200 to 300 basis points, in each case depending on the percentage of the borrowing base utilized. 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.

The Company uses interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. As of June 30, 2021, we had interest rate swaps with a total notional amount of $200.0 million.

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, 2021 would cost us approximately $0.6 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 principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures.

As of June 30, 2021, our management, including our principal executive officer and principal 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 principal executive officer and principal 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 principal executive officer and principal 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, 2021.

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, 2021, 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, 2020.

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

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 Exchange Act, of our common stock during the quarter ended June 30, 2021.

Period	Total Number of Shares Purchased[1]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs[2]
Month #1				
April 1, 2021 to April 30, 2021	—	$ —	—	$ 68.1 million
Month #2				
May 1, 2021 to May 31, 2021	—	—	—	68.1 million
Month #3				
June 1, 2021 to June 30, 2021	82	18.93	—	68.1 million
Total	82	$ 18.93	—	$ 68.1 million

(1) Represents shares surrendered in satisfaction of tax withholding 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 of shares of our 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.

Item 6. ***Exhibits.***

Exhibit No.	Description	Reference
3.1	Restated Certificate of Incorporation of Northern Oil and Gas, Inc., dated August 24, 2018	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 27, 2018
3.2	Certificate of Amendment to the Restated Certificate of Incorporation of Northern Oil and Gas, Inc., dated September 18, 2020	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 24, 2020
3.3	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 May 15, 2018
3.4	Certificate of Designations of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock of Northern Oil and Gas, Inc., dated November 22, 2019	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on November 26, 2019
3.5	Certificate of Amendment to the Certificate of Designations of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock of Northern Oil and Gas, Inc., dated January 2, 2020	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 6, 2020
3.6	Certificate of Amendment to the Certificate of Designations of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock of Northern Oil and Gas, Inc., dated January 17, 2020	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 22, 2020
4.1	Indenture, dated May 15, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.50% Senior Secured Second Lien Notes due 2023)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018
4.2	First Supplemental Indenture, dated September 18, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 18, 2018
4.3	Second Supplemental Indenture, dated October 5, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 9, 2018
4.4	Third Supplemental Indenture, dated November 22, 2019, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on November 26, 2019
4.5	Fourth Supplemental Indenture, dated February 18, 2021, among the Company and Wilmington Trust, National Association, as trustee and collateral agent	Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed with the SEC on February 23, 2021
4.6	Indenture, dated February 18, 2021, between the Company and Wilmington Trust, National Association, as trustee (including Form of 8.125% Senior Note due 2028)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on February 23, 2021
4.7	Warrant to Purchase Common Shares, dated April 1, 2021, by and between Northern Oil and Gas, Inc. and Reliance Marcellus, LLC	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on April 6, 2021
10.1	Third Amendment to the Second Amended and Restated Credit Agreement, dated May 27, 2021, by and among Northern Oil and Gas, Inc. and Wells Fargo Bank, National Association 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 June 2, 2021

10.2	Registration Rights Agreement, dated April 1, 2021, by and between Northern Oil and Gas, Inc. and Reliance Marcellus, LLC	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on April 6, 2021
31.1	Certification of the Principal 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 Principal 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 Principal Executive Officer and Principal 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	Inline XBRL Instance Document	Filed herewith
101.SCH	Inline XBRL Taxonomy Extension Schema Document	Filed herewith
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document	Filed herewith
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith
104	The cover page from Northern Oil and Gas, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, formatted in Inline XBRL and contained in Exhibit 101	Filed herewith

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, 2021	By:	/s/ Nicholas O'Grady
			Nicholas O'Grady, Chief Executive Officer and principal executive officer (on behalf of Registrant)
Date:	August 5, 2021	By:	/s/ Chad Allen
			Chad Allen, Chief Financial Officer and principal accounting officer

Exhibit 31.1

CERTIFICATION

I, Nicholas O’Grady certify that:

1. I have reviewed this quarterly report on Form 10-Q of Northern Oil and Gas, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting;

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Dated: August 5, 2021

By: /s/ Nicholas O’Grady

Nicholas O’Grady
Principal Executive Officer

Exhibit 31.2

CERTIFICATION

I, Chad Allen certify that:

1. I have reviewed this quarterly report on Form 10-Q of Northern Oil and Gas, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

    c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting;

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Dated: August 5, 2021

By: /s/ Chad Allen

Chad Allen
Principal Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Northern Oil and Gas, Inc., (the "Company") on Form 10-Q for the quarterly period ended June 30, 2021, as filed with the United States Securities and Exchange Commission on the date hereof, (the "Report"), the undersigned officers of the Company hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: August 5, 2021	By: /s/ Nicholas O'Grady
	Nicholas O'Grady Principal Executive Officer
Dated: August 5, 2021	By: /s/ Chad Allen
	Chad Allen Principal Financial Officer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.