**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**WASHINGTON, D.C. 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 September 30, 2018**

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

**Commission file number: 001-35330**

# Lilis Energy, Inc.

(Name of registrant as specified in its charter)

| **Nevada** | **74-3231613** |
|---|---|
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**1800 Bering Drive, Suite 510, Houston, Texas 77057**
(Address of principal executive offices, including zip code)

**Registrant's telephone number including area code: (817) 585-9001**

Indicate by check mark if 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 past 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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company, or emerging growth company (as defined in Rule 12b-2 of the 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 October 31, 2018, 71,969,815 shares of the registrant's common stock were issued and outstanding.

**Lilis Energy, Inc.**

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### *Forward-Looking Statements*

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. The statements contained in this report that are not historical facts are forward-looking statements that represent management's beliefs and assumptions based on currently available information. Forward-looking statements include information concerning our possible or assumed future results of operations, business strategies, need for financing, competitive position, and potential growth opportunities. Our forward-looking statements do not consider the effects of future legislation or regulations. Forward-looking statements include all statements that are not historical facts and can be identified by the use of forward-looking terminology such as the words "believes," "intends," "may," "should," "anticipates," "expects," "could," "plans," "estimates," "projects," "targets," or comparable terminology or by discussions of strategy or trends. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we cannot give any assurances that these expectations will prove to be correct. Such statements by their nature involve risks and uncertainties that could significantly affect expected results, and actual future results could differ materially from those described in such forward-looking statements.

Among the factors that could cause actual future results to differ materially are the risks and uncertainties discussed in this report and in our Annual Report (as defined in Note 2 hereafter). Should our underlying assumptions prove incorrect or the consequences of the aforementioned risks worsen, actual results could differ materially from those expected. Forward-looking statements speak only as to the date hereof. All such forward-looking statements and any subsequent written or oral forward-looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the statements contained herein or referred to in this section and any other cautionary statements that may accompany such forward-looking statements. Except as otherwise required by applicable law, we disclaim any intention or obligation to update publicly or revise such statements whether as a result of new information, future events or otherwise.

There may also be other risks and uncertainties that we are unable to predict at this time or that we do not now expect to have a material adverse impact on our business.

## GLOSSARY

In this Quarterly Report, the following abbreviation and terms are used:

*Bbl*. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude, condensate or natural gas liquids.

*Bcf*. Billion cubic feet of natural gas.

*Bcfe*. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

*BLM*. The Bureau of Land Management of the United States Department of the Interior.

*BOE*. One barrel of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

*BOE/d*. Barrels of oil equivalent per day.

*BO/d*. Barrel of oil per day.

*BTU or British Thermal Unit*. The quantity of heat required to raise the temperature of one pound mass of water by 28.5 to 59.5 degrees Fahrenheit.

*Completion*. Installation of permanent equipment for production of oil or natural gas.

*Condensate*. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure but that, when produced, is in the liquid phase at surface pressure and temperature.

*Development well*. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

*Drilling locations*. Total gross locations specifically quantified by management to be included in our multi-year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors.

*Dry well or dry hole*. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

*Exploratory well*. A well drilled to find a new field or to find a new reservoir. Generally, an exploratory well in any well that is not a development well, an extension well, a service well or a stratigraphic well.

*FERC*. The Federal Energy Regulatory Commission.

*Field*. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same geological structural feature and/or stratigraphic condition.

*Formation*. An identifiable layer of subsurface rocks named after its geographical location and dominant rock type.

*Gross acres, gross wells, or gross reserves*. A well, acre or reserve in which we own a working interest, reported at the 100% or 8/8ths level. For example, the number of gross wells is the total number of wells in which we own a working interest.

*Lease*. A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract of land.

*Leasehold*. Mineral rights leased in a certain area to form a project area.

*MBBLs*. One thousand barrels of crude oil or other liquid hydrocarbons.

*MBOE*. One thousand barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

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

*Mcfe*. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

*MMbtu*. One million British Thermal Units.

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

*Net acres or net wells*. The sum of fractional ownership working interests in gross acres or gross wells. The number of net acres or wells is the sum of the fractional working interests owned in gross acres or wells expressed as whole numbers and fractions of whole numbers.

*NGL*. Natural gas liquids, or liquid hydrocarbons found as a by-product of natural gas.

*Overriding royalty interest*. Is similar to a basic royalty interest except that it is created out of the working interest. For example, an operator possesses a standard lease providing for a basic royalty to the lessor or mineral rights owner of 1/8 of 8/8. This then entitles the operator to retain 7/8 of the total oil and natural gas produced. The 7/8 in this case is the 100% working interest the operator owns. This operator may assign his working interest to another operator subject to a retained 1/8 overriding royalty. This would then result in a basic royalty of 1/8, an overriding royalty of 1/8 and a working interest of 3/4. Overriding royalty interest owners have no financial or other obligation or responsibility for developing and operating the property. The only expenses borne by the overriding royalty owner are a share of the production or severance taxes and sometimes costs incurred to make the oil or gas salable.

*Plugging and abandonment*. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

*Production*. Natural resources, such as oil or gas, flowed or pumped out of the ground.

*Productive well*. A producing well or a well that is mechanically capable of production.

*Proved developed oil and natural gas reserves.* Proved developed oil and natural gas reserves are proved reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

*Proved reserves*. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, 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 reserves*. Proved undeveloped oil and natural gas reserves are proved 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 recompletion.

*Project*. A targeted development area where it is probable that commercial oil and/or natural gas can be produced from new wells.

*Prospect*. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

*Recompletion*. The process of re-entering an existing well bore that is either producing or not producing and modifying the existing completion and/or completing new reservoirs in an attempt to establish new production or increase or re-activate existing production.

*Reserves*. Estimated remaining quantities of oil, natural gas and natural gas liquids anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

*Reservoir*. A subsurface formation containing a natural accumulation of producible natural gas and/or oil that is naturally trapped by impermeable rock or other geologic structures or water barriers and is individual and separate from other reservoirs.

*Secondary Recovery*. A recovery process that uses mechanisms other than the natural pressure or fluid drive of the reservoir, such as gas injection or water flooding, to produce residual oil and natural gas remaining after the primary recovery phase.

*Shut-in*. A well suspended from production or injection but not abandoned.

*Standardized measure*. The present value of estimated future cash flows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

*Successful*. A well is determined to be successful if it is producing oil or natural gas in paying quantities.

*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 oil or natural gas regardless of whether such acreage contains proved reserves.

*Water-flood*. A method of secondary recovery in which water is injected into the reservoir formation to maintain or increase reservoir pressure and displace residual oil and enhance hydrocarbon recovery.

*Working interest.* The operating interest that gives the lessees/owners the right to drill, produce and conduct operating activities on the property, and to receive a share of the production revenue, subject to all royalties, overriding royalties and other burdens, all development costs, and all risks in connection therewith.

# PART I – FINANCIAL INFORMATION

## Item 1. Financial Statements.

**Lilis Energy, Inc. and Subsidiaries**
**Condensed Consolidated Balance Sheets**
***(In thousands, except share and per share data)***

| | September 30, 2018 | December 31, 2017 |
|---|---|---|
| | (Unaudited) | |
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 24,954 | $ 17,462 |
| Accounts receivables, net of allowance of $25 and $39, respectively | 17,758 | 7,426 |
| Derivative instruments | 532 | — |
| Prepaid expenses and other current assets | 2,259 | 584 |
| Total current assets | 45,503 | 25,472 |
| Oil and natural gas properties, full cost method of accounting | | |
| Unproved | 167,324 | 101,771 |
| Proved | 308,691 | 141,717 |
| Less: accumulated depreciation, depletion, amortization and impairment | (90,583) | (73,183) |
| Total oil and natural gas properties, net | 385,432 | 170,305 |
| Other property and equipment, net | 451 | 76 |
| Other assets | 124 | 91 |
| Total other assets | 575 | 167 |
| Total assets | $ 431,510 | $ 195,944 |
| **LIABILITIES AND STOCKHOLDERS' DEFICIT** | | |
| Current liabilities: | | |
| Accounts payable | $ 30,336 | $ 10,488 |
| Accrued liabilities | 26,901 | 7,634 |
| Revenue payable | 13,445 | 6,460 |
| Dividends payable | 6,527 | — |
| Derivative instruments - current | 5,201 | 853 |
| Total current liabilities | 82,410 | 25,435 |
| Asset retirement obligations | 1,228 | 726 |
| Long-term debt, less current maturities | 166,259 | 127,794 |
| Long-term derivative instruments | 56,650 | 72,937 |
| Long-term deferred revenue liabilities | 52,515 | — |
| Total liabilities | 359,062 | 226,892 |
| Commitments and contingencies (Note 17) | | |
| Redeemable Preferred Stock: | | |
| Series C convertible preferred stock, $0.0001 par value; stated value of $1,000; 100,000 shares authorized, 100,000 issued and outstanding with a liquidation preference of $124,923 at September 30, 2018 | 97,506 | — |
| Stockholders' deficit: | | |
| Common stock, $0.0001 par value per share; 150,000,000 shares authorized, 65,768,908 and 53,368,331 shares issued and outstanding as of September 30, 2018 and December 31, 2017, respectively, of which 253,598 shares are being held as treasury stock as of September 30, 2018 | 6 | 5 |
| Additional paid-in capital | 301,039 | 272,335 |
| Accumulated deficit | (325,106) | (303,288) |
| Treasury stock (253,598 shares at cost) | (997) | — |
| Total stockholders' deficit | (25,058) | (30,948) |
| Total liabilities and stockholders' deficit | $ 431,510 | $ 195,944 |

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

**Lilis Energy, Inc. and Subsidiaries**
**Condensed Consolidated Statements of Operations (Unaudited)**
***(In thousands, except share and per share data)***

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Revenues: | | | | |
| Oil sales | $ 15,976 | $ 4,378 | $ 42,819 | $ 11,040 |
| Natural gas sales | 1,538 | 592 | 3,572 | 1,631 |
| Natural gas liquid sales | 1,968 | 420 | 4,969 | 1,108 |
| Total revenues | 19,482 | 5,390 | 51,360 | 13,779 |
| Operating expenses: | | | | |
| Production costs | 2,772 | 1,409 | 8,532 | 3,336 |
| Gathering, processing and transportation | 963 | 405 | 2,297 | 842 |
| Production and ad valorem taxes | 1,446 | 290 | 3,604 | 710 |
| General and administrative | 6,838 | 10,943 | 24,682 | 36,273 |
| Depreciation, depletion, amortization and accretion | 7,172 | 1,443 | 17,572 | 3,946 |
| Total operating expenses | 19,191 | 14,490 | 56,687 | 45,107 |
| Operating income (loss) | 291 | (9,100) | (5,327) | (31,328) |
| Other income (expense): | | | | |
| Other income | 1 | 151 | 2 | 19 |
| Loss from commodity derivatives | (4,811) | — | (9,383) | — |
| Change in fair value of financial instruments | 10,612 | 6,368 | 19,499 | 4,254 |
| Interest expense | (8,949) | (3,656) | (26,609) | (11,084) |
| Total other income (expense) | (3,147) | 2,863 | (16,491) | (6,811) |
| Net loss before income taxes | (2,856) | (6,237) | (21,818) | (38,139) |
| Income tax expense | — | — | — | — |
| Net loss | (2,856) | (6,237) | (21,818) | (38,139) |
| Less: | | | | |
| Dividends on Series C convertible preferred stock | (2,410) | — | (6,527) | — |
| Dividends and deemed dividends on Series B convertible preferred stock | — | — | — | (4,635) |
| Dividends on conditionally redeemable 6% preferred stock | — | — | — | (122) |
| Net loss attributable to common stockholders | $ (5,266) | $ (6,237) | $ (28,345) | $ (42,896) |
| | | | | |
| Net loss per common share-basic and diluted: (Note 14) | | | | |
| Basic | $ (0.08) | $ (0.12) | $ (0.47) | $ (1.06) |
| Diluted | $ (0.09) | $ (0.12) | $ (0.47) | $ (1.06) |
| | | | | |
| Weighted average common shares outstanding: | | | | |
| Basic | 64,572,104 | 50,785,588 | 60,082,902 | 40,596,281 |
| Diluted | 88,710,081 | 50,785,588 | 60,082,902 | 40,596,281 |

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

**Lilis Energy, Inc. and Subsidiaries**
**Condensed Consolidated Statements of Changes in Stockholders' Deficit**
**(in thousands, except share data)**
**(Unaudited)**

| | Common Shares | | Additional | Treasury Stock | | Accumulated | |
|---|---|---|---|---|---|---|---|
| | Shares | Amount | Paid In Capital | Shares | Amount | Deficit | Total |
| **Balance, December 31, 2017** | 53,368,331 | $ 5 | $ 272,335 | — | $ — | $ (303,288) | $ (30,948) |
| Stock based compensation | — | — | 7,654 | — | — | — | 7,654 |
| Common stock for restricted stock | 802,860 | — | — | — | — | — | — |
| Common stock withheld for taxes on stock-based compensation | (315,439) | — | (1,051) | — | — | — | (1,051) |
| Common stock for acquisition of oil and gas properties | 6,940,722 | 1 | 24,777 | — | — | — | 24,778 |
| Exercise of warrants and stock options | 4,972,434 | — | 3,628 | — | — | — | 3,628 |
| Reclassification of warrant derivative liabilities | — | — | 223 | — | — | — | 223 |
| Purchase of treasury stock | — | — | — | (253,598) | (997) | — | (997) |
| Dividends on Series C convertible preferred stock | — | — | (6,527) | — | — | — | (6,527) |
| Net loss | — | — | — | — | — | (21,818) | (21,818) |
| **Balance, September 30, 2018** | 65,768,908 | $ 6 | $ 301,039 | (253,598) | $ (997) | $ (325,106) | $ (25,058) |

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

**Lilis Energy, Inc. and Subsidiaries**
**Condensed Consolidated Statements of Cash Flows (Unaudited)**
***(In thousands)***

| | Nine Months Ended September 30, 2018 | Nine Months Ended September 30, 2017 |
|---|---|---|
| **Cash flows from operating activities:** | | |
| Net loss | $ (21,818) | $ (38,139) |
| Adjustments to reconcile net loss to net cash provided by (used in) operating activities: | | |
| Stock based compensation | 7,654 | 14,477 |
| Bad debt expense (recovery) | (14) | 12 |
| Amortization of debt issuance cost | 1,130 | 1,673 |
| Accretion of debt discount | 11,893 | 5,030 |
| Payable in-kind interest | 9,810 | 3,258 |
| Loss from commodity derivatives, net | 7,250 | — |
| Net cash settlement paid for commodity derivative contracts | 2,133 | — |
| Change in fair value of financial instruments | (19,499) | (4,254) |
| Depreciation, depletion, amortization and accretion | 17,572 | 3,946 |
| **Changes in operating assets and liabilities:** | | |
| Accounts receivable | (7,818) | (2,364) |
| Prepaid expenses and other assets | (1,707) | (13) |
| Accounts payable and accrued liabilities | 27,093 | 8,764 |
| Proceeds for options associated with salt water disposal infrastructure and future gas midstream services recorded as deferred revenue in other long-term liabilities | 50,000 | — |
| Net cash provided by (used in) operating activities | 83,679 | (7,610) |
| **Cash flows from investing activities:** | | |
| Net proceeds from sale of DJ Basin properties | — | 1,082 |
| Acquisition of oil and gas properties | (61,416) | — |
| Capital expenditures | (129,490) | (64,771) |
| Net cash used in investing activities | (190,906) | (63,689) |
| **Cash flows from financing activities:** | | |
| Proceeds from issuance of Series C Preferred Stock | 100,000 | — |
| Proceeds from private placement | — | 18,400 |
| Proceeds from exercise of accordion features of 2016 Term Loans | — | 6,706 |
| Proceeds from Bridge Loan and Second Lien Term Loans | — | 94,700 |
| Proceeds from issuance of Riverstone Term Loans | 50,000 | — |
| Debt Issuance Costs | (2,546) | — |
| Equity Financing Costs | (2,494) | — |
| Repayment of debt | (31,821) | (40,390) |
| Repurchase of common stock | (997) | — |
| Proceeds from exercise of warrants and stock options | 3,628 | 392 |
| Payment for tax withholding on stock-based compensation | (1,051) | (2,427) |
| Net cash provided by financing activities | 114,719 | 77,381 |
| Net increase in cash, cash equivalents and restricted cash | 7,492 | 6,082 |
| Cash, cash equivalents and restricted cash at beginning of period | 17,462 | 11,738 |
| Cash, cash equivalents and restricted cash at end of period | $ 24,954 | $ 17,820 |
| **Supplemental disclosure:** | | |
| Cash paid for interest | $ 3,776 | $ 1,594 |

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

**NOTE 1 - ORGANIZATION**

Lilis Energy, Inc. ("Lilis" or the "Company") is an independent oil and natural gas exploration and production company focused on the Delaware Basin in Winkler, Loving, and Reeves Counties, Texas and Lea County, New Mexico.

**NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES**

*Principles of Consolidation and Presentation*

The condensed consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, namely Brushy Resources, Inc. ("Brushy Resources"), ImPetro Operating, LLC, ImPetro Resources, LLC, Lilis Operating Company, LLC, and Hurricane Resources LLC. All significant intercompany accounts and transactions have been eliminated in consolidation. The unaudited condensed consolidated financial statements included herein reflect all adjustments (consisting only of normal, recurring adjustments) which are, in our opinion, necessary for a fair presentation of the information as of and for the periods presented. These unaudited condensed consolidated interim financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP") for interim financial information and the instructions to Quarterly Report on Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all disclosures required under GAAP for complete consolidated financial statements.

These unaudited condensed consolidated financial statements should be read in conjunction with our annual report on Form 10–K for the twelve months ended December 31, 2017, as filed with the Securities and Exchange Commission ("SEC") on March 9, 2018 (the "Annual Report").

*Use of Estimates*

The accompanying condensed consolidated financial statements are prepared in conformity with GAAP which requires the Company to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities; disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period; and the quantities and values of proved oil, natural gas and natural gas liquid ("NGL") reserves used in calculating depletion and assessing impairment of its oil and natural gas properties. The most significant estimates pertain to the evaluation of unproved properties for impairment, proved oil and natural gas reserves and related cash flow estimates used in the depletion and impairment of oil and natural gas properties; the timing and amount of transfers of our unevaluated properties into our amortizable full cost pool; the fair value of embedded derivatives and commodity derivative contracts, accrued oil and natural gas revenues and expenses valuation of options and warrants, inducement transactions and common stock; and the allocation of general administrative expenses. Actual results could differ significantly from these estimates.

*Reclassifications*

Certain reclassifications have been made to the prior period financial statements to conform to the current period presentation. These reclassifications have no effect on the Company's previously reported results of operations. For the three and nine months ended September 30, 2017, the income from operator's overhead recovery of approximately $0.27 million and $0.33 million, respectively, have been reclassified from revenue to operating expense as an offset against general and administrative expenses in the condensed consolidated statement of operations.

*Recently Adopted Accounting Standards*

On January 1, 2018, the Company adopted the new accounting standard, Accounting Standards Codification, ASC 606, *Revenue from Contracts with Customers* and all the related amendments (the "New Revenue Standard") using the modified retrospective method. In accordance with the modified retrospective method, comparative information is not restated and continues to be reported under the accounting standards in effect for those periods. The cumulative effect of initially adopting the New Revenue Standard, if any, is recorded as an adjustment to the opening balance of retained earnings. The Company's revenue from customers is derived from production and sales of crude oil, natural gas and NGLs and recognized when control is transferred to the customer. As operator, the Company may market production on behalf of joint interest partners and various royalty owners. Under the terms of our joint operating agreements, the Company does not take control of the production attributable to our joint interest partners and the various royalty owners. Consequently, the Company recognizes revenues only for its share of the production. In accordance with the New Revenue Standard requirements, the impact of adoption on our condensed consolidated statements of operations and condensed consolidated balance sheets was as follows:

| ***Three Months Ended September 30, 2018*** | **As Reported** | **Balances without Adoption of ASC 606** | **Increase (Decrease)** |
|---|---|---|---|
| **Condensed Consolidated Statements of Operations:** | | | |
| Revenues | $ 19,482 | $ 19,508 | $ (26) |
| Operating expenses | $ (963) | $ (989) | $ (26) |
| | | | |
| ***Nine Months Ended September 30, 2018*** | | | |
| **Condensed Consolidated Statements of Operations:** | | | |
| Revenues | $ 51,360 | $ 51,451 | $ (91) |
| Operating expenses | $ (2,297) | $ (2,388) | $ (91) |
| | | | |
| ***As of September 30, 2018*** | | | |
| **Condensed Consolidated Balance Sheets:** | | | |
| Accounts receivable | $ 17,758 | $ 17,849 | $ (91) |
| Accrued liabilities | $ (26,901) | $ (26,992) | $ (91) |

As shown in this comparison table, there is no impact on the net loss from the New Revenue Standard adoption and, therefore, no adjustment to the opening balance of accumulated deficit. Prior to the adoption of the New Revenue Standard, the revenue line included the value of our natural gas gatherer's contractual volume retainage fee, with an offsetting cost included in the gathering, processing and marketing costs line. In accordance with the New Revenue Standard, the Company will only recognize revenues for its share of the production, resulting in the removal of the retainage fee approximating $26,000 and $91,000 from both revenues and operating expenses during the three and nine months ended September 30, 2018, respectively.

On July 13, 2017, the Financial Accounting Standards Board ("FASB") issued a two-part ASU 2017-11, *(Part I) Accounting for Certain Financial Instruments with Down Round Features, (Part II) Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Redeemable Noncontrolling Interests with a Scope Exception* (ASU 2017-11). Part I of ASU 2017-11 simplifies the accounting for certain financial instruments with down round features by requiring companies to disregard the down round feature when assessing whether the instrument is indexed to its own stock, for purposes of determining liability or equity classification. Companies that provide earnings per share (EPS) data will adjust their basic EPS calculation for the effect of the feature when triggered (that is, when the exercise price of the related equity-linked financial instrument is adjusted downward because of the down round feature) and will also recognize the effect of the trigger within equity. Part II of ASU 2017-11 is not applicable to the Company since it addresses concerns relating to an indefinite deferral available to private companies with mandatorily redeemable financial instruments and certain noncontrolling interests. The provisions of ASU 2017-11 related to down rounds are effective for public business entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. Early adoption is permitted for all organizations. The Company elected to adopt ASU 2017-11 on January 1, 2018. The Company's SOS Warrant Liability (as described in Note 6) was accounted for as a derivative instrument solely because of its down round feature. Any outstanding SOS Warrants as of the date of adoption were reclassified to equity and the Company will no longer recognize any gain or loss based on the fair value of the SOS Warrants. No other derivatives instruments were affected by the adoption of ASU 2017-11.

On January 5, 2017, the FASB issued ASU 2017-01 B*usiness Combinations (Topic 805): Clarifying the Definition of a Business* (ASU 2017-01), which clarifies the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. ASU 2017-01 introduces a screen for determining when assets acquired are not a business and clarifies that a business must include, at a minimum, an input and a substantive process that contribute to an output to be considered a business. This standard is effective for fiscal years beginning after December 15, 2017, including interim periods within that reporting period. The Company adopted ASU 2017-01 on January 1, 2018. On March 15, 2018, the Company completed an acquisition of proved and unproved properties from OneEnergy Partners, LLC ("OEP") (See Note 5-Acquisitions and Divestitures). As a result of the adoption of ASU 2017-01, the Company accounted for the acquisition as an asset purchase instead of a business combination. As a result, acquisition costs of approximately $1.1 million were capitalized as part of the acquisition and the purchase price was allocated to unproved and proved properties based on relative fair value.

On January 1, 2018, the Company retroactively adopted ASU No. 2016-18, *Statement of Cash Flows (Topic 230)*: *Restricted Cash* (a consensus of the FASB Emerging Issues Task Force).” This ASU requires the statements of cash flows to present the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are now included with cash and cash equivalents when reconciling the beginning of period and end of period amounts presented on the statements of cash flows. The retrospective application of this new accounting guidance resulted in a decrease of $0.6 million in “restricted cash” in Cash Flows from Investing Activities, an increase of $0.6 million in “Cash, Cash Equivalents, and Restricted Cash, beginning of the period,” and an increase of $0.6 million in “Cash, Cash Equivalents, and Restricted Cash, end of period” in the Company's accompanying condensed consolidated statement of cash flows for the nine months ended September 30, 2017, from what was previously presented in our Quarterly Report on Form 10–Q for the quarterly period ended September 30, 2017. The $0.6 million in restricted cash was refunded to the Company during the three and nine months ended September 30, 2017.

*Recently Issued Accounting Pronouncements*

The Company considers the applicability and impact of all Accounting Standards Updates (“ASUs”). The ASUs listed below were assessed and determined to be either not applicable or are expected to have minimal impact on its consolidated financial position and/or results of operations.

On July 30, 2018, the FASB issued ASU 2018-11, Leases (Topic 842): *Targeted Improvements*, which provides entities with an additional (and optional) transition method to adopt the new leases standard. Under this new transition method, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. ASU 2018-11 also provides lessors with a practical expedient, by class of underlying asset, to not separate non-lease components from the associated lease component and, instead, to account for those components as a single component if the non-lease components otherwise would be accounted for under Topic 606 and both the timing and pattern of transfer of the non-lease component(s) and associated lease component are the same, and the lease component, if accounted for separately, would be classified as an operating lease. If the non-lease component or components associated with the lease component are the predominant component of the combined component, an entity is required to account for the combined component in accordance with Topic 606. Otherwise, the entity must account for the combined component as an operating lease in accordance with Topic 842. The Company expects to adopt the new lease standard on January 1, 2019 using the optional transition method.

On June 20, 2018, the FASB issued ASU 2018-07, Improvements to Nonemployee Share-Based Payment Accounting, which supersedes most of the prior accounting guidance on nonemployee share-based payments, and instead aligns it with existing guidance on employee share-based payments in Topic 718. As a result, nonemployee share-based payment transactions will be measured by estimating the fair value of the equity instruments that an entity is obligated to issue and the measurement date will be consistent with the measurement date for employee share-based payment awards (i.e., grant date for equity-classified awards). Probability is to be considered on nonemployee awards with performance conditions. The classification will continue to be subject to the requirements of Topic 718, Compensation - Stock Compensation, although cost recognition of nonemployee awards will remain unchanged (i.e., as if paid in cash). The ASU provides certain accounting alternatives to private companies, including the use of the calculated value method and a one-time option to apply intrinsic value to liability-classified awards. The amendments become effective for public business entities for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. For all other entities, the ASU is effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted, but no earlier than an entity’s adoption date of Topic 606. The Company elected to early adopt the ASC 2018-07 during the quarter ended September 30, 2018. As a result, during the three and nine months ended September 30, 2018, the Company recognized $0.5 million and $2.4 million of non-employee share-based compensation, respectively.

On February 25, 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* (ASU 2016-02), which requires companies to recognize the assets and liabilities for the rights and obligations created by long-term leases of assets on the balance sheet. The standard will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. The Company plans on adopting this guidance on January 1, 2019, using the modified retrospective approach. Oil and natural gas leases are scoped out of ASU 2016-02. The Company is currently evaluating the impact this ASU will have on the consolidated financial statements and related disclosures. As a part of the assessment work to-date, the Company has engaged an external consulting firm and is evaluating agreements under this ASU as well as assessing the completeness of the lease population. While the Company cannot currently estimate the quantitative effect that ASU 2016-02 will have on its consolidated financial statements, the adoption will increase asset and liability balances on the consolidated balance sheets due to the required recognition of right-of-use assets and corresponding lease liabilities. The quantitative effect is also dependent on active leases at the time of adoption. In addition, the Company is in the process of implementing new lease accounting software to properly account for the leases upon adoption.

*Accrued Liabilities*

At September 30, 2018 and December 31, 2017, the Company's accrued liabilities consisted of the following:

| | September 30, 2018 | December 31, 2017 |
|---|---|---|
| | ($ in thousands) | |
| Accrued bonus | $ 1,234 | $ 3,000 |
| Accrued capital expenditures | 20,927 | 3,615 |
| Other accrued liabilities | 4,740 | 1,019 |
| | 26,901 | $ 7,634 |

**NOTE 3 – REVENUE**

Revenue is recognized when control passes to the purchaser which generally occurs when production is transferred to the purchaser. The Company measures revenue as the amount of consideration it expects to receive in exchange for the commodities transferred. All of the Company’s revenues from contracts with customers represent products transferred at a point in time as control is transferred to the customer.

The Company records revenue based on consideration specified in its contracts with its customers. The amounts collected on behalf of third parties are recorded in revenue payable. The Company recognizes revenue in the amount that reflects the consideration it expects to receive in exchange for transferring control of those goods to the customer. The contract consideration in the Company’s variable price contracts is typically allocated to specific performance obligations in the contract according to the price stated in the contract. Payment is generally received one or two months after the sale has occurred.

*Crude oil revenues*

Crude oil from our operated properties is produced and stored in field tanks. The Company recognizes crude oil revenue when control passes to the purchaser. The Company’s crude oil is currently sold under a single short-term contract. The purchaser’s commitment includes all quantities of crude oil from the leases that are covered by the contract, with no quantity-based restrictions or variable terms. Pricing is based on posted indexes for crude oil of similar quality, less a fees deduction that is subject to negotiation. As of the most recent contract amendments, the negotiable fees deduction is $5.25 per barrel from June 1, 2018 through July 31, 2018, then $5.15 per barrel from August 1, 2018 through February 28, 2019, continuing on a month-to-month basis thereafter unless renegotiated or canceled upon 30 days' notice. The posted index prices change monthly based on the average of daily index price points for each sales month.

*Natural gas and NGL revenues*

Natural gas is produced and transported via pipelines to gas processing facilities. NGLs are extracted from the natural gas at the processing facilities and processed natural gas and NGLs are marketed and sold separately on the Company’s behalf after processing. All of our operated natural gas production is sold under one of three natural gas contracts which are long-term in nature; however, one of these natural gas contracts includes 30-day cancellation provisions, and the Company therefore classifies such contract as short-term. The processor’s commitment to sell on the Company’s behalf includes all quantities of natural gas and NGLs produced from specific wellbores or dedicated acreage as defined in the contract, with no quantity-based restrictions or variable terms. The gas contracts are generally market based pricing less adjustments for transportation and processing fees. A portion of natural gas delivered to the processing plants is used as fuel at the processing plant without reimbursement. The Company recognizes revenue for natural gas and NGLs when control passes at the tailgate of the processing plant.

*Gathering, processing and transportation*

Natural gas must be transported to a gas processing plant facility for treatment and to extract NGLs, then the final residue gas and liquid products are marketed for sale to end users at the tailgate of the plant. As a result of these activities, the Company incurs costs that are contractually passed to it from the gatherer per customary industry practice. Such costs include fees for gathering the gas and moving it from wellhead to plant inlet, plant electricity usage, inlet compression, carbon dioxide and hydrogen sulfide treatments, processing tax, fuel usage, and marketing at the tailgate. Gathering, processing and transportation costs are presented as operating expenses in the Company's condensed consolidated statement of operations.

*Imbalances*

Natural gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of its share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. The Company did not have any significant natural gas imbalance positions as of September 30, 2018 and December 31, 2017.

*Contract balances and prior period performance obligations*

The Company is entitled to payment from purchasers once its performance obligations have been satisfied upon delivery of the product, at which point payment is unconditional, and the Company records these invoiced amounts as accounts receivable in its condensed consolidated balance sheets.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and also recorded as accounts receivable in the accompanying condensed consolidated balance sheets. In this scenario, payment is unconditional, as the Company has satisfied its performance obligations through delivery of the relevant product. As a result, the Company has concluded that its product sales do not give rise to contract assets or liabilities under the New Revenue Standard.

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGL sales may not be received for 30 to 60 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the customer and the price that will be received for the sale of the product. Additionally, to the extent actual volumes and prices of oil, natural gas and NGLs are unavailable for a given reporting period because of timing or information not received from third party purchasers, the expected sales volumes and prices for those barrels of oil, cubic feet of gas and gallons of NGLs are also estimated.

The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls in place for its estimation process, and any identified differences between its revenue estimates and actual revenue received historically have not been significant.

*Significant judgments*

The Company engages in various types of transactions in which midstream entities process its gas and subsequently market resulting NGLs and residue gas to third-party customers on the Company's behalf per gas purchase contracts. These types of transactions require judgment to determine whether the Company is the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net. The Company maintains control of the natural gas and NGLs during processing and consider itself the principal in these arrangements.

*Practical expedients*

A significant number of the Company's product sales are short-term in nature with contract terms of one year or less. For those contracts, the Company has utilized the practical expedient in the New Revenue Standard that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have contract terms greater than one year, the Company has utilized the practical expedient in the New Revenue Standard that states that it is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

The following table disaggregates the Company's revenue by contract type (*in thousands*):

| ***Three Months Ended September 30, 2018*** | **Short-term contracts** | **Long-term contracts** | **Total** |
|---|---|---|---|
| Crude Oil | $ 15,976 | $ — | $ 15,976 |
| Natural Gas | 264 | 1,274 | 1,538 |
| NGLs | 338 | 1,630 | 1,968 |
| Gathering, processing and transportation | (165) | (798) | (963) |

| ***Nine Months Ended September 30, 2018*** | **Short-term contracts** | **Long-term contracts** | **Total** |
|---|---|---|---|
| Crude oil | $ 42,819 | $ — | $ 42,819 |
| Natural gas | 817 | 2,755 | 3,572 |
| NGLs | 1,136 | 3,833 | 4,969 |
| Gathering, processing and transportation | (525) | (1,772) | (2,297) |

*Customer Credit Risk*

Our principal exposure to credit risk is through receivables from the sale of our oil and natural gas production of approximately $11.5 million and $4.7 million at September 30, 2018 and December 31, 2017, respectively, and through actual and accrued receivables from our joint interest partners of approximately $3.0 million and $2.6 million at September 30, 2018 and December 31, 2017, respectively. We are subject to credit risk due to the concentration of our oil and natural gas receivables with our most significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

*Major Customers*

During the three and nine months ended September 30, 2018, the Company's major customers as a percentage of total revenue consisted of the following:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Texican Crude & Hydrocarbon, LLC | 80% | 86% | 84% | 83% |
| Lucid Energy Delaware, LLC | 17% | —% | 12% | —% |
| ETC Field Services LLC | 2% | 14% | 3% | 15% |
| Other below 10% | 1% | —% | 1% | 2% |
| | 100% | 100% | 100% | 100% |

Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

**NOTE 4 - OIL AND NATURAL GAS PROPERTIES**

The Company uses the full cost method of accounting for oil and natural gas operations. Under this method, costs related to the exploration, non-production related development and acquisition of oil and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling, developing and completing productive wells, and any other costs directly related to acquisition and exploration activities. Proceeds from property sales are generally applied as a credit against capitalized exploration and development costs, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of proved reserves.

Depletion of exploration and development costs and depreciation of wells and tangible production assets is computed using the units-of-production method based upon estimated proved oil and natural gas reserves. Costs included in the depletion base to be amortized include (a) all proved capitalized costs including capitalized asset retirement costs net of estimated salvage values, less accumulated depletion, and (b) estimated future development cost to be incurred in developing proved reserves, that are not otherwise included in capitalized costs.

Under the full cost method of accounting, capitalized oil and natural gas property costs less accumulated depletion (net of deferred income taxes) may not exceed an amount equal to the sum of the present value, discounted at 10%, of estimated future net revenues from proved oil and natural gas reserves and the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are not subject to amortization. Should capitalized costs exceed this ceiling, an impairment expense is recognized. The present value of estimated future net cash flows was computed by applying a flat oil price to forecast revenues from estimated future production of proved oil and natural gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves (assuming the continuation of existing economic conditions), less any applicable future taxes. As of September 30, 2018, the ceiling value of the Company's reserves was calculated based upon SEC pricing of $63.43 per barrel for oil, $2.92 per MMBtu for natural gas and $60.26 per barrel for NGLs.

The Company accounts for its unproven long-lived assets in accordance with ASC Topic 360-10-05, *Accounting for the Impairment or Disposal of Long-Lived Assets* (ASC Topic 360-10-05). ASC Topic 360-10-05 requires that long-lived assets be reviewed for impairment whenever events or changes in circumstances indicate that the historical carrying value of an asset may no longer be appropriate. Costs associated with undeveloped acreage are excluded from the depletion base until it is determined whether proved reserves can be assigned to the properties. When proved reserves are assigned to such properties or one or more specific properties are deemed to be impaired, the cost of such properties is added to the full cost pool, which is subject to depletion.

The following table sets forth a summary of oil and natural gas property costs (net of divestitures) not being amortized at September 30, 2018 and December 31, 2017:

| | September 30, 2018 | December 31, 2017 |
|---|---|---|
| | *(In thousands)* | |
| **Unproved unevaluated acreage:** | | |
| Beginning balance | $ 101,771 | $ 24,461 |
| Lease acquisitions | 89,035 | 78,110 |
| Transfer and other reclassification to proved properties | (23,482) | (800) |
| Total unproved acreage | $ 167,324 | $ 101,771 |
| **Unevaluated Wells:** | | |
| Beginning balance | $ — | $ 7,453 |
| Additions | — | — |
| Reclassification to evaluated properties | — | (7,453) |
| Total unevaluated wells not subject to DD&A | $ — | $ — |

During the nine months ended September 30, 2018, the Company completed an assessment of its inventory of unproved acreage for impairment which resulted in $11.1 million being transferred from unproved properties to proved properties in the full cost pool due to defective titles on certain leases. During the three and nine months ended September 30, 2017, no impairment was recorded on the Company’s unproved oil and natural gas properties.

For the three months ended September 30, 2018 and 2017, depreciation, depletion, amortization and accretion expense related to proved properties was $7.2 million and $1.4 million, respectively. For the nine months ended September 30, 2018 and 2017, depreciation, depletion, amortization and accretion expense related to proved properties was $17.6 million and $3.9 million, respectively.

## NOTE 5 – ACQUISITIONS AND DIVESTITURES

*Ameredev Leasehold Acreage Exchange Transaction*

On August 1, 2018, the Company entered into a Leasehold Exchange Agreement (the "Ameredev Exchange Agreement") with Ameredev II, LLC (“Ameredev”) to exchange certain leasehold interests located in Lea County, New Mexico owned by the Company for certain leasehold interests owned by Ameredev also located in Lea County, New Mexico. The Ameredev Exchange Agreement closed on September 14, 2018, and required the Company pay Ameredev $12,500 for each net mineral acre received in excess of the Company’s net mineral acres traded to Ameredev. The Company’s payment for excess net mineral acres was $0.7 million. In connection with the Ameredev Exchange Agreement, the Company assumed the working interests in four wells pursuant to which Ameredev advanced the Company $6.5 million for the estimated costs of the four wells. At the closing of the exchange transaction, the Company refunded the $6.5 million to Ameredev. The four wells are located in Lea County, New Mexico and operated by the Company. The total proceeds paid to Ameredev was $7.2 million and was recorded as an adjustment to the full cost pool.

*Felix Holdings Leasehold Acreage Exchange Transaction*

On June 4, 2018, the Company entered into a Leasehold Exchange Agreement (the "Felix Exchange Agreement") with Felix Energy Holdings II, LLC (“Felix”) to exchange certain leasehold interest located in Loving and Winkler Counties in Texas owned by the Company for certain leasehold interest located in the same counties owned by Felix. The Agreement closed on August 14, 2018, with an effective date of May 1, 2018. In addition to the Felix leasehold interests, the Company acquired certain working interests in two wells operated by the Company in Winkler County, Texas. The Company paid Felix for the well costs incurred by Felix to drill and complete the two wells, less any revenues paid to Felix. The final settlement was a payment of $0.4 million which was recorded as an adjustment to the full cost pool.

*OEP Acquisition*

On January 30, 2018, the Company entered into a Purchase and Sale Agreement (the "Purchase and Sale Agreement") by and between the Company and OneEnergy Partners Operating, LLC ("OEP"), pursuant to which the Company agreed to purchase from OEP, and OEP agreed to sell to the Company, certain oil and natural gas properties and related assets for a purchase price of $70 million, subject to customary purchase price adjustments (the "OEP Acquisition"). The properties acquired by the Company pursuant to the Purchase and Sale Agreement consist of leasehold acreage in the Delaware Basin in Lea County, New Mexico. On March 15, 2018, the Company completed the OEP Acquisition whereby the Company paid $40 million in cash and issued 6,940,722 shares of the Company's common stock valued at approximately $24.8 million for a total purchase price of approximately $64.9 million, before acquisition costs and customary purchase price adjustments. The value of the shares issued was determined using the closing price of the Company's stock on the date of closing.

The OEP Acquisition was accounted for as an asset purchase of proved properties and unproved properties using relative fair value of the assets acquired. The proved producing properties were valued based on internal estimates of future production using strip pricing and the present value discounted at 10%. Unproved properties acquired were valued using a market approach.

The purchase price and the value of the assets acquired in the OEP Acquisition were as follows:

| ***(in thousands, except per share amount)*** | | |
|---|---|---|
| Cash | $ | 40,000 |
| Common stock issued (6,940,722 shares at $3.57) | | 24,778 |
| Transaction costs and purchase price adjustments | | 1,074 |
| Total purchase price | $ | 65,852 |
| | | |
| Proved properties | $ | 4,168 |
| Unproved properties | | 61,684 |
| | $ | 65,852 |

*VPD Acquisition*

On February 28, 2018, the Company completed the acquisition of certain leasehold interests and other oil and gas assets in Loving and Winkler Counties, Texas from VPD Texas, L.P. ("VPD") for cash consideration of $10.6 million including $0.5 million of related acquisition costs (the "VPD Acquisition"). The VPD Acquisition was recorded at fair value which was the total cash consideration of approximately $11.1 million. VPD is an affiliate of Värde Partners, Inc. ("Värde"). Värde participated as lead lender in the Company's Second Lien Loan (as defined below in Note 6) transaction in 2017 and as investor of the Company's Series C Preferred Stock transaction in January 2018. As a result, the VPD Acquisition is considered a related party transaction. See Note 11 - *Related Party Transactions.*

In connection with the above VPD Acquisition and pursuant to Article XVI.3(b) of the Joint Operating Agreement dated February 28, 2018 (the "JOA") entered into between VPD and ImPetro Operating, LLC ("Operator"), a subsidiary of the Company, the Company has committed to the following drilling commitments:

- drill and complete two horizontal wells ("Initial Commitment Wells") no later than December 31, 2018; and
- drill and complete at least two additional horizontal wells ("Subsequent Commitment Wells") that target the Wolfcamp A/B Formation no later than December 31, 2019.

The Company has a one-time option to extend the deadline by an additional 75 days by providing written notice to VPD of such election on or before August 31, 2018, in the case of the Initial Commitment Wells, and August 31, 2019, in the case of the Subsequent Commitment Wells.

As of September 30, 2018, the Company has spud the first two Initial Commitment Wells and is on track to fulfill its obligations ahead of the December 31, 2018 deadline.

The purchase price and the value of the assets acquired in the VPD Acquisition were as follows:

| (in thousands, except per share amount) | | |
|---|---|---|
| Cash purchase price | $ | 10,611 |
| | | |
| Proved properties | $ | 3,185 |
| Unproved properties | | 7,426 |
| | $ | 10,611 |

*Anadarko Acquisition*

On May 3, 2018, the Company completed the acquisition of certain leasehold interests and other oil and gas assets in Loving and Winkler Counties, Texas from Anadarko for cash consideration of $7.1 million. The acquisition includes unproved leaseholds and non-consent proved producing oil and natural gas properties. As a result, the transaction is accounted for as an asset acquisition using the fair value of $7.1 million.

*KEW Acquisition*

As of December 31, 2017, the Company completed the acquisition of unproved acreage in Winkler County, Texas from KEW Drilling, a Delaware limited partnership ("KEW"), for cash consideration of $48.9 million plus $0.8 million of related acquisition costs. The acquisition was accounted for as an asset acquisition using the relative fair value, which was the total cash consideration of approximately $49.7 million.

***Divestitures***

*DJ Basin Properties Divestiture*

On June 30, 2017, the Company entered into a purchase and sale agreement with Nanke Energy LLC for the divestiture of all of its oil and natural gas properties located in the Denver-Julesburg Basin (the "DJ Basin") for consideration of $2 million, subject to customary post-closing purchase price adjustments. The sale of the Company's DJ Basin assets did not significantly alter the relationship between capitalized costs and proved reserves, and as such, all proceeds were recorded as adjustments to the Company's full cost pool with no gain or loss recognized. The DJ Basin assets were sold to an entity owned by the Company's former chief financial officer and, therefore, the divestiture is considered a related party transaction. See Note 10 - *Related Party Transactions*. The net proceeds of $1.08 million received on June 30, 2017 included an offset against $0.7 million of severance pay and $0.22 million of net sales adjustments due to the purchaser.

**NOTE 6 - FAIR VALUE OF FINANCIAL INSTRUMENTS**

The Company measures the fair value of its financial assets on a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 - Other inputs that are directly or indirectly observable in the marketplace.

- Level 3 - Unobservable inputs which are supported by little or no market activity.

The fair value hierarchy also requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

The determination of the fair values of our derivative contracts incorporates various factors, which include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved. The Company utilizes counterparty rate of default values to assess the impact of non-performance risk when evaluating both our liabilities to, and receivables from, counterparties.

*Recurring Fair Value Measurements*

| | Fair Value Measurement Classification | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| | (in thousands) | | | |
| **As of September 30, 2018** | | | | |
| Oil and natural gas derivative swap contracts | $ — | $ (1,244) | $ — | $ (1,244) |
| Oil and natural gas derivative collar contracts | — | (4,163) | — | (4,163) |
| Oil and natural gas derivative basis swap contracts | — | (2,697) | — | (2,697) |
| Second Lien Term Loan conversion features | — | — | (53,215) | (53,215) |
| Total | $ — | $ (8,104) | $ (53,215) | $ (61,319) |
| **As of December 31, 2017** | | | | |
| Oil and natural gas derivative swap contracts | $ — | $ (706) | $ — | $ (706) |
| Oil and natural gas derivative collar contracts | — | (147) | — | (147) |
| Warrant liabilities | — | — | (223) | (223) |
| Second Lien Term Loan conversion features | — | — | (72,714) | (72,714) |
| Total | $ — | $ (853) | $ (72,937) | $ (73,790) |

The Company's derivative liability associated with the Second Lien Loan (as defined below) and warrants are measured using Level 3 inputs as follows:

*Second Lien Term Loan Conversion Features:* Under the terms of the Company's second lien credit agreement, dated as of April 26, 2017, by and among the Company, certain subsidiaries of the Company, as guarantors (the "Guarantors"), Wilmington Trust, National Association, as administrative agent (the "Agent"), and the lenders party thereto (the "Lenders"), including Värde ., as lead lender (the "Lead Lender"), as amended (the "Second Lien Credit Agreement"), the Lead Lender has the option to convert 70% of the principal amount of each tranche of the Second Lien Term Loan (the "Second Lien Loan") under the Second Lien Credit Agreement, together with accrued paid-in-kind interest and the make-whole premium on such principal amount (together the "Conversion Sum") into shares of common stock. The make-whole premium is the cash amount representing the excess of (a) the present value at such repayment, prepayment or acceleration date or the date the obligations otherwise become due and payable in full of (1) the sum of the principal amount repaid, prepaid or accelerated *plus* (2) the interest accruing on such principal amount from the date of such repayment, prepayment or acceleration through the maturity date (excluding accrued but unpaid paid-in-kind interest to the date of such repayment, prepayment or acceleration), such present value to be computed using a discount rate equal to the Treasury Rate plus 50 basis points discounted to the repayment, prepayment or acceleration date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months), over (b) the principal amount of the Second Lien Loan repaid, prepaid or accelerated. The number of shares of common stock issued will be based on the division of 70% of the Conversion Sum by the conversion price then in effect.

The Company also has the option to cause the Second Lien Loan to convert if, at the time of exercise of the Company's conversion option, the closing price of the Company's common stock has been at least 150% of the Conversion Price (as defined in Note 9) then in effect for at least 20 of the 30 immediately preceding trading days. The features of the make-whole premium in the Second Lien Loan require the conversion features to be recorded as embedded derivatives and bifurcated from its host contracts, the Second Lien Loan, and accounted for separately from the debt. The conversion features contained in the Second Lien Loan are recorded as a derivative liability at fair value each reporting period based upon values determined through the use of discounted lattice models of the Second Lien Loan under the Second Lien Credit Agreement. Change in fair value is accounted for in the condensed consolidated statement operations. As of September 30, 2018, the fair value of the embedded derivative liability was $53.2 million. As of December 31, 2017, the fair value of the embedded derivative under the Second Lien Credit Agreement associated with the Second Lien Loan conversion features was a liability of approximately $72.7 million. As a result, the Company recorded an unrealized gain of $10.6 million and an unrealized gain of $19.5 million on the change in fair value of derivative liabilities associated with the Second Lien Loan conversion features for the three and nine months ended September 30, 2018, respectively. During the three and nine months ended September 30, 2017, the Company recorded an unrealized loss of $6.2 million and $3.5 million, respectively, on the change in fair value of derivative liabilities associated with the Second Lien Loan conversion features.

The fair value of the holder conversion features was determined using a binomial lattice model based on certain assumptions including (i) the Company’s stock price, (ii) risk-free rate, (iii) expected volatility, (iv) the Company’s implied credit rating, and (v) the implied credit yield of the Second Lien Loan.

*SOS Warrant Liability.* On June 23, 2016, in conjunction with the merger with Brushy Resources, the Company issued to SOS Investment LLC ("SOS") warrants to purchase up to 200,000 shares of the Company’s common stock at an exercise price of $25.00 (the "SOS Warrants"). The SOS Warrants contain a price protection feature that will automatically reduce the exercise price if the Company enters into another agreement pursuant to which warrants are issued with a lower exercise price. As of December 31, 2017, the fair value of the SOS Warrant liability was approximately $0.2 million. As a result of the Company’s early adoption of ASU 2017-11, “Accounting for Financial Instruments with Down Round Features” on January 1, 2018, the $0.2 million on the SOS Warrants were reclassified from current liabilities to stockholders’ equity at January 1, 2018. During the three and nine months ended September 30, 2017, the Company recorded an unrealized gain of approximately $0.3 million on the SOS Warrant liability.

**NOTE 7 - ASSET RETIREMENT OBLIGATIONS ("ARO")**

The Company’s ARO represent the present value of the estimated cash flows expected to be incurred to plug, abandon and remediate producing properties, excluding salvage values, at the end of their productive lives in accordance with applicable laws. Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs. Revisions in estimated liabilities can also include, but are not limited to, revisions of estimated inflation rates, changes in property lives and expected timing of settlement.

The following table summarizes the changes in the Company’s ARO for the nine months ended September 30, 2018 and year ended December 31, 2017:

| | Nine Months Ended September 30, 2018 | Year Ended December 31, 2017 |
|---|---|---|
| | *(In thousands)* | |
| ARO, beginning of period | $ 952 | $ 1,257 |
| Additional liabilities incurred | 295 | 20 |
| Accretion expense | 77 | 82 |
| Liabilities settled | (87) | (288) |
| Revision in estimates | 7 | (119) |
| ARO, end of period | 1,244 | 952 |
| Less: current portion of ARO | (16) | (226) |
| ARO, non-current | $ 1,228 | $ 726 |

**NOTE 8 - DERIVATIVES**

The Company's derivative instruments include the following:

| | September 30, 2018 | December 31, 2017 |
|---|---|---|
| | *(in thousands)* | |
| Current assets: | | |
| Commodity derivatives | 532 | — |
| Total | 532 | — |
| | | |
| Current liabilities: | | |
| Commodity derivatives | 5,201 | 853 |
| Total | 5,201 | 853 |
| | | |
| Long-term liabilities: | | |
| Embedded derivatives | 53,215 | 72,714 |
| Warrant derivatives | — | 223 |
| Commodity derivatives | 3,435 | — |
| Total | 56,650 | 72,937 |

*Embedded Derivatives*

As discussed in Note 6, the Second Lien Loan contains conversion features that are exercisable at the option of the Lead Lender or the Company. The conversion features have been identified as embedded derivatives which (i) contain economic characteristics that are not clearly and closely related to the host contract, the Second Lien Loan, and (ii) separate, stand-alone instruments with similar terms would qualify as derivative instruments. As such, the conversion features were bifurcated and accounted for separately from the Second Lien Loan. The conversion features are recorded at fair value for each reporting period with changes in fair value included in the Company's condensed consolidated statement of operations for each reporting period. As of September 30, 2018 and December 31, 2017, the fair value of the derivative liability was $53.2 million and $72.7 million, respectively. As a result, the Company recognized an unrealized gain of $10.6 million and $19.5 million in its condensed consolidated statement of operations for the three and nine months ended September 30, 2018, respectively. During the three and nine months ended September 30, 2017, the Company recognized unrealized gains of approximately $6.4 million and approximately $3.5 million, respectively, in its consolidated statement of operations.

*Warrant Derivatives*

As of September 30, 2017, the warrant derivatives included $0.2 million fair value of 200,000 underlying warrants which were issued to SOS as of June 23, 2016 at an exercise price of $25.00. The warrants contained a price protection feature that will automatically reduce the exercise price if the Company enters into another agreement pursuant to which warrants are issued with a lower exercise price. However, as of September 30, 2018, following the adoption of ASU 2017-11 on January 1, 2018, the outstanding balance of the SOS Warrants as of the date of adoption were reclassified to equity and the Company no longer recognizes any gain or loss based on the fair value of the SOS Warrants. The SOS Warrants expired on June 23, 2018. During the three and nine months ended September 30, 2017, the Company recognized a net unrealized gain of approximately $0.01 million and $0.8 million, respectively, on the SOS Warrant and other warrants that were no longer classified as derivative instruments as of September 30, 2018.

***Commodity Derivatives***

To reduce the impact of fluctuations in oil and natural gas prices on the Company’s revenues and to protect the economics of property acquisitions, the Company periodically enters into derivative contracts with respect to a portion of its projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. The derivative contracts may include fixed-for-floating price swaps (whereby, on the settlement date, the Company will receive or pay an amount based on the difference between a pre-determined fixed price and a variable market price for a notional quantity of production), put options (whereby the Company pays a cash premium in order to establish a fixed floor price for a notional quantity of production and, on the settlement date, receives the excess, if any, of the fixed price floor over a variable market price), and costless collars (whereby, on the settlement date, the Company receives the excess, if any, of a variable market price over a fixed floor price up to a fixed ceiling price for a notional quantity of production).

These hedging activities, which are governed by the terms of our Second Lien Credit Agreement, are intended to support oil and natural gas prices at targeted levels and manage exposure to oil and natural gas price fluctuations. It is our policy to enter into derivative contracts only with counterparties that are creditworthy and competitive market makers. All of our derivatives are with non-lender counterparties and are designated as unsecured. Certain of our derivative counterparties may require the posting of cash collateral under certain conditions. It is never the Company's intention to enter into derivative contracts for speculative trading purposes.

All of our derivatives are accounted for as mark-to-market activities. Under ASC Topic 815, "Derivatives and Hedging," these instruments are recorded on the Company's condensed consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. The Company nets derivative assets and liabilities by commodity for counterparties where a legal right to such offset exists. Changes in the derivatives' fair values are recognized in current earnings since the Company has elected not to designate its current derivative contracts as cash flow hedges for accounting purposes.

The following table presents the Company's derivative position for the production periods indicated as of September 30, 2018:

| Description | | Notional Volume (Bbls/d) | Production Period | Weighted Average Price ($/Bbl) |
|---|---|---|---|---|
| Oil Swaps | | 900 | October 2018 - December 2018 | $ 57.68 |
| | | | | |
| Basis Swaps [1] | | 1,500 | October 2018 - December 2018 | $ (5.62) |
| Basis Swaps [1] | | 2,492 | January 2019 - December 2019 | $ (6.85) |
| Basis Swaps [1] | | 1,500 | January 2020 - December 2020 | $ (5.62) |
| | | | | |
| 3 Way Collar | Floor sold price (put) | 1,252 | January 2019 - December 2019 | $ 45.00 |
| 3 Way Collar | Floor purchase price (put) | 1,252 | January 2019 - December 2019 | $ 55.00 |
| 3 Way Collar | Ceiling sold price (call) | 1,252 | January 2019 - December 2019 | $ 70.61 |
| | | | | |
| Oil Collar | Floor purchase price (put) | 1,723 | October 2018 - December 2018 | $ 58.35 |
| Oil Collar | Ceiling sold price (call) | 1,723 | October 2018 - December 2018 | $ 70.02 |
| Oil Collar | Floor purchase price (put) | 1,000 | January 2019 - June 2019 | $ 52.50 |
| Oil Collar | Ceiling sold price (call) | 1,000 | January 2019 - June 2019 | $ 67.60 |

[1] The weighted average price under these basis swaps is the fixed price differential between the index prices of Midland WTI and the Cushing WTI.

| | Nine Months Ended September 30, 2018 | Year Ended December 31, 2017 |
|---|---|---|
| | *(in thousands)* | |
| Beginning fair value of commodity derivatives | $ (853) | $ — |
| Change in fair value of derivative instruments | (9,383) | (1,063) |
| Net settlements paid on crude oil derivative contracts | 1,940 | 96 |
| Change in settlements accrued on crude oil derivative contracts | 192 | 114 |
| Ending fair value of commodity derivatives, net | $ (8,104) | $ (853) |

The following information summarizes the gross fair values of derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on the Company's condensed consolidated balance sheets:

| | As of September 30, 2018 | | |
|---|---|---|---|
| | Gross Amount of Recognized Assets and Liabilities | Gross Amounts Offset in the Condensed Consolidated Balance Sheets | Net Amounts Presented in the Condensed Consolidated Balance Sheets |
| | *(in thousands)* | | |
| **Offsetting Derivative Assets:** | | | |
| Current asset | $ 532 | $ — | $ 532 |
| Long-term asset | — | — | — |
| Total asset | $ 532 | $ — | $ 532 |
| **Offsetting Derivative Liabilities:** | | | |
| Current liability | $ 5,201 | $ — | $ 5,201 |
| Long-term liability | 3,435 | — | 3,435 |
| Total liability | $ 8,636 | $ — | $ 8,636 |

| | As of December 31, 2017 | | |
|---|---|---|---|
| | Gross Amount of Recognized Assets and Liabilities | Gross Amounts Offset in the Condensed Consolidated Balance Sheets | Net Amounts Presented in the Condensed Consolidated Balance Sheets |
| | *(in thousands)* | | |
| **Offsetting Derivative Assets:** | | | |
| Current asset | $ — | $ — | $ — |
| Long-term asset | — | — | — |
| Total asset | $ — | $ — | $ — |
| **Offsetting Derivative Liabilities:** | | | |
| Current liability | $ 853 | $ — | $ 853 |
| Long-term liability | — | — | — |
| Total liability | $ 853 | $ — | $ 853 |

**NOTE 9 – LONG-TERM DEBT**

| | September 30, 2018 | December 31, 2017 |
|---|---|---|
| | *(In thousands)* | |
| Riverstone First Lien Loans associated with the Amended and Restated Senior Secured Term Loan Credit Agreement, due 2021, net of debt issuance costs and debt discount | $ 48,018 | $ — |
| 6% Bridge Loans associated with the amended First Lien Term Loan, due 2019, net of debt issuance costs | — | 30,363 |
| 8.25% Second Lien Term Loans, due 2021, net of debt issuance costs and debt discount | 118,241 | 96,431 |
| 6% note payable to SOS Investment, LLC, due 2019 | — | 1,000 |
| Other notes payable, due 2018 | — | 11 |
| Total long-term debt | $ 166,259 | $ 127,805 |
| Less: current portion | — | (11) |
| Total long-term debt, net of current portion | $ 166,259 | $ 127,794 |

As of September 30, 2018 and December 31, 2017, the carrying amounts of the Company's Riverstone First Lien Loans and Second Lien Term Loans were as follows *(in thousands)*:

| | Principal Amount | Paid-in-kind Interest | Unamortized Debt Issuance Costs & Debt Discount | Carrying Amount |
|---|---|---|---|---|
| ***September 30, 2018:*** | | | | |
| Riverstone First Lien Loans, due January 2021 | $ 50,000 | $ — | $ (1,982) | $ 48,018 |
| Second Lien Term Loans, due April 2021 | 150,000 | 15,561 | (47,320) | 118,241 |
| Total: | $ 200,000 | $ 15,561 | $ (49,302) | $ 166,259 |
| ***December 31, 2017:*** | | | | |
| Bridge Loans associated with the amended First Lien Term Loan, due September 2019 | $ 30,000 | $ 807 | $ (444) | $ 30,363 |
| Second Lien Term Loans, due April 2021 | 150,000 | 5,752 | (59,321) | 96,431 |
| Total: | $ 180,000 | $ 6,559 | $ (59,765) | $ 126,794 |

*Second Lien Credit Agreement*

On April 26, 2017, the Company entered into the Second Lien Credit Agreement comprised of convertible loans in an aggregate initial principal amount of up to $125 million available in two separate tranches. The first tranche consists of an $80 million term loan (the “Second Lien Loan”), which was fully drawn and funded on April 26, 2017. The second tranche consists of up to $45 million in delayed-draw term loans (the “Delayed Draw Term Loan” and, together with the Second Lien Loan to be funded on or before February 28, 2019, at the request of the Company, subject to certain conditions, in a single draw or in multiple draws. Each tranche of Second Lien Loans will bear interest at a rate of 8.25% per annum, compounded quarterly in arrears and payable only in-kind by increasing the principal amount of the loan by the amount of the interest due on each interest payment date.

On October 3, 2017, the Company, the Guarantors, the Agent and the Lenders entered into Amendment No. 1 to the Second Lien Credit Agreement (“Amendment No. 1 to the Second Lien Credit Agreement”). The purpose of Amendment No. 1 to the Second Lien Credit Agreement is to waive certain conditions precedent to the drawing of the Delayed Draw Term Loan under the Second Lien Credit Agreement and to provide for the funding of such Delayed Draw Term Loan upon the signing of the lease acquisition agreement with KEW. The Company borrowed the full $45.0 million available under the Delayed Draw Term Loan on October 4, 2017.

On October 19, 2017, the Company entered into a second amendment to the Second Lien Credit Agreement ("Amendment No. 2 to the Second Lien Credit Agreement"), by and among the Company, the Guarantors, the Agent and the Lenders, including the Lead Lender. Amendment No. 2 to the Second Lien Credit Agreement permits the Company to incur the Incremental Bridge Loan under the First Lien Credit Agreement ("Bridge Loan").

On November 10, 2017, the Company entered into a third amendment to the Second Lien Credit Agreement ("Amendment No. 3 to the Second Lien Credit Agreement"), by and among the Company, the Guarantors, the Agent and the Lenders, including the Lead Lender. Amendment No. 3 to the Second Lien Credit Agreement increased by $25.0 million the amount of delayed draw term loans available for borrowing under the Second Lien Credit Agreement. The additional $25.0 million of Delayed Draw Term Loan was drawn on November 10, 2017. The $25.0 million of proceeds from these loans may be used to fund oil and natural gas property acquisitions, subject to certain limitations, to fund drilling and completion costs or for other general corporate purposes.

On January 31, 2018, the Company entered into a fourth amendment to the Second Lien Credit Agreement with the Guarantors, the Lenders, including the Lead Lender, and the Agent ("Amendment No. 4 to the Second Lien Credit Agreement").

The purpose of Amendment No. 4 to the Second Lien Credit Agreement was to, among other matters:

- permit the Company to enter into the Riverstone First Lien Credit Agreement and incur the Riverstone First Lien Loans and related liens;
- permit the Company to issue the Series C Preferred Stock; and
- after the issuance of the Series C Preferred Stock, reduce from two to one the maximum number of members of the Board of Directors, the lenders under the Second Lien Credit Agreement will have the right to appoint following the conversion of the convertible loans under the Second Lien Credit Agreement.

The Second Lien Loans are secured by second priority liens on substantially all of the Company's and the Guarantors' assets, including their oil and natural gas properties located in the Delaware Basin, and all of the obligations thereunder are unconditionally guaranteed by each of the Guarantors. The Second Lien Loans mature on April 26, 2021. The Second Lien Loans are subject to mandatory prepayment with the net proceeds of certain asset sales, casualty events and debt incurrences, subject to the right of the Company to reinvest the net proceeds of asset sales and casualty events within 180 days and, in the case of asset sales and casualty events, prepayment of the Bridge Loan. The Company may not voluntarily prepay the Second Lien Loans prior to March 31, 2019, except (a) in connection with a Change of Control (as defined in the Second Lien Credit Agreement) or (b) if the closing price of our common stock on the principal exchange on which it is traded has been equal to or greater than 110% of the Conversion Price (as defined below) for at least 20 of the 30 trading days immediately preceding the prepayment. The Company will be required to pay a make-whole premium in connection with any mandatory or voluntary prepayment of the Second Lien Loans.

Each tranche of the Second Lien Loans is separately convertible at any time, in full and not in part, at the option of the Lead Lender, as follows:

- 70% of the principal amount of each tranche of Second Lien Loans, together with accrued and unpaid interest and the make-whole premium on such principal amount, will convert into a number of newly issued shares of common stock determined by dividing the total of such principal amount, accrued and unpaid interest and make-whole premium by $5.50 (subject to certain customary adjustments, the "Conversion Price"); and
- 30% of the principal amount of each tranche of Second Lien Loans, together with accrued and unpaid interest and the make-whole premium on such principal amount, will convert on a dollar for dollar basis into a new term loan (the "Take Back Loans").

The terms of the Take Back Loans will be substantially the same as the terms of the Second Lien Loans, except that the Take Back Loans will not be convertible and will bear interest payable in cash at a rate of LIBOR plus 9% (subject to a 1% LIBOR floor).

Additionally, the Company will have the option to convert the Second Lien Loans, in whole or in part, into shares of common stock at any time or from time to time if, at the time of exercise of the Company's conversion option, the closing price of the Company's common stock on the principal exchange on which it is traded has been at least 150% of the Conversion Price then in effect for at least 20 of the 30 immediately preceding trading days. Conversion at the Company's option will occur on the same terms as conversion at the Lenders' option.

The Second Lien Loans contains certain customary representations and warranties and affirmative and negative covenants, including covenants relating to: maintenance of books and records, financial reporting and notification, compliance with laws;

maintenance of properties and insurance; limitations on incurrence of indebtedness, investments, dividends and other restricted payments, lease obligations, hedging and capital expenditures; and maintenance of a specified asset coverage ratio. The Second Lien Loans also provide for events of default, including failure to pay any principal or interest when due, failure to perform or observe covenants, cross-default on certain outstanding debt obligations, the failure of a Guarantor to comply with the provisions of its Guaranty, and bankruptcy or insolvency events, subject to certain specified cure periods. The amounts under the Second Lien Loans could be accelerated and be due and payable upon an event of default. As of September 30, 2018, the Company was in compliance with all restrictive covenants.

As discussed in Note 6, *Fair Value of Financial Instruments,* and Note 8, *Derivatives*, the Company separately accounts for the embedded conversion features of the Second Lien Loans as a derivative instrument in accordance with accounting guidance relating to recording embedded derivatives at fair value. The initial fair value of the embedded derivatives is recorded as a debt discount to the convertible Second Lien Loan. The debt discount is amortized over the term of the Second Lien Loans using effective interest rate. A portion of the Second Lien Loans were extinguished on October 10, 2018 (see Note 18, *Subsequent Events).*

*Riverstone First Lien Credit Agreement*

On January 30, 2018, the Company entered into an Amended and Restated Senior Secured Term Loan Credit Agreement (the “Riverstone First Lien Credit Agreement”), by and among the Company, the subsidiaries of the Company party thereto as guarantors, Riverstone Credit Management LLC, as administrative agent and collateral agent, and the lenders party thereto. Effective at closing under the Riverstone First Lien Credit Agreement, which occurred on January 31, 2018, the Riverstone First Lien Credit Agreement amended and restated the Company's First Lien Credit Agreement, which was entered into by the Company on September 29, 2016, and subsequently amended on April 26, 2017, July 25, 2017, and October 19, 2017 (the "First Lien Credit Agreement").

Pursuant to the Riverstone First Lien Credit Agreement, the lenders thereunder agreed to make term loans to the Company in the aggregate principal amount of $50 million (the “Riverstone First Lien Loans”), all of which were funded in full at closing at an original issue discount of 1.0% of the principal amount. The Riverstone First Lien Credit Agreement provides the potential for additional term loans of up to $30 million, as requested by the Company and subject to certain conditions, which additional loans were uncommitted at closing.

The Company used approximately $31.5 million of the proceeds of the Riverstone First Lien Loans to repay in full its obligations under and retire the First Lien Credit Agreement during the first quarter of 2018. The Riverstone First Lien Credit Agreement was subsequently paid and settled on October 10, 2018 (see Note 18*, Subsequent Events).*

*Amendments to Riverstone First Lien Credit Agreement and Second Lien Credit Agreement*

On February 20, 2018, the Company entered into the following amendments to its existing credit agreements (collectively, the “Amendments”): (i) Amendment No. 1 to the Riverstone First Lien Credit Agreement and (ii) Amendment No. 5 to the Second Lien Credit Agreement. Pursuant to the Amendments and a consent letter received from the Purchasers (as defined in Note 12 below), in their capacity as the holders of all of the issued and outstanding shares of Series C Preferred Stock, the Company has been granted the right to repurchase shares of its common stock for an aggregate purchase price up to $10 million (subject to certain exceptions and conditions).

The commencement of any repurchase of shares of common stock is subject to compliance with applicable law, Board approval, and market conditions.

*Interest Expense*

The components of interest expense are as follows (*in thousands)*:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Interest on term loans | $ 1,238 | $ 229 | $ 3,776 | $ 1,086 |
| Interest on notes payable | — | 17 | — | 36 |
| Paid-in-kind interest on term loans | 3,373 | 1,917 | 9,810 | 3,258 |
| Amortization of debt financing costs | 249 | 51 | 1,130 | 1,673 |
| Amortization of discount on term loans | 4,089 | 1,442 | 11,893 | 5,031 |
| Total | $ 8,949 | $ 3,656 | $ 26,609 | $ 11,084 |

**NOTE 10 - LONG-TERM DEFERRED REVENUE LIABILITIES**

*SCM Water LLC's Option to Exercise Purchase of Salt Water Disposal Assets*

In July 2018, the Company entered into a water gathering and disposal agreement with SCM Water, LLC ("SCM Water"). The water gathering project will complement the Company's existing water disposal infrastructure, and the Company has reserved the right to recycle its produced water. SCM Water will commence, upon receipt of regulatory approval, to build out new gathering and disposal infrastructure to all of the Company's current and future well locations in Lea County, New Mexico, and Winkler County, Texas. All future capital expenditures will be fully funded by SCM Water and will be designed to accommodate all water produced by the Company's operations. The Company will act as contract operator of SCM Water's salt water disposal wells ("SWD wells"). The Company has sold to SCM Water an option to acquire the Company's existing water infrastructure, a system which is comprised of approximately 14 miles of pipeline and one SWD well for cash consideration upon closing, with additional payments based on reaching certain milestones. The Company is actively working on permitting additional SWD well locations and the option is expected to be exercised once permits are obtained. The Company anticipates that the majority of its water will eventually be disposed through the future SCM Water system at a competitive gathering rate under the agreement. Total cash consideration for the water gathering and disposal infrastructure is $20.0 million. On July 25, 2018, the Company received an upfront non-refundable payment of $10.0 million for the option to acquire its existing water infrastructure for the firm transportation and pricing for crude oil and $5.0 million for a prefunded drilling bonus. Additionally, the Company received $2.5 million on October 1, 2018 as a bonus for the grant of area right-of-way/easement and will receive an additional $2.5 million bonus upon hitting the target of 40,000 barrels per day of produced water. As of September 30, 2018, the Company accounted for the $17.5 million as deferred revenue liability until SCM Water exercise its option to acquire the Company's salt water disposal infrastructure.

*Crude Oil Gathering Agreement and Option Agreement*

On May 21, 2018, the Company entered into a crude oil gathering agreement and option agreement with Salt Creek Midstream, LLC ("SCM"). The crude oil gathering agreement (the "Gathering Agreement") enables SCM to (i) design, engineer, and construct a gathering system which will provide gathering services for the Company's crude oil and (ii) gather the Company's crude oil on the gathering system in certain production areas located in Winkler and Loving Counties, Texas and Lea County, New Mexico. Construction of the gathering system has commenced and is expected to be completed in November 2018. The Gathering Agreement has a term of 12 years that automatically renews on a year to year basis until terminated by either party.

SCM and the Company also entered into an option agreement (the "Option Agreement") whereby the Company granted an option to SCM to provide certain midstream services related to natural gas in Winkler and Loving Counties, Texas and Lea County, New Mexico, subject to the expiration and terms of the Company's existing gas agreement. The Option Agreement has a term commencing May 21, 2018 and terminating January 1, 2027, pursuant to its one-time option. As consideration for this option, the Company received a one-time of payment $35.0 million which was recorded in long-term deferred revenue.

**NOTE 11 - RELATED PARTY TRANSACTIONS**

During the nine months ended September 30, 2018 and 2017, the Company was engaged in the following transactions with certain related parties:

| Related Party | Transactions | Nine Months Ended September 30, 2018 | 2017 |
|---|---|---|---|
| | | ($ in thousands) | |
| **Directors and Officers:** | | | |
| Ronald D. Ormand (Chief Executive Officer) | Receivable for tax withholding on vested restricted shares. Additional shares will be canceled to cover this tax withholding. | $ 441 | $ — |
| | Total: | $ 441 | $ — |
| Brennan Short (former Chief Operating Officer) | Consulting fees paid to MMZ Consulting, Inc. ("MMZ") which is owned by Mr. Short. Mr. Short is the sole member of MMZ. | $ — | $ 204 |
| | Total: | $ — | $ 204 |
| Kevin Nanke (former Chief Financial Officer) | Purchased the DJ Basin properties from the Company through Nanke Energy, LLC | $ — | $ 2,000 |
| | Total: | $ — | $ 2,000 |
| Värde Partners, Inc. ("Värde")(1) | The Company acquired oil and natural gas interests from VPD, an affiliate of Värde | $ 10,705 | $ — |
| | Total: | $ 10,705 | $ — |

(1) Värde is the lead lender in the Company's Second Lien Loans (see Note 9 – *Long-term Debts)* and also participated in the issuance of Series C 9.75% Convertible Preferred Stock in January 2018 (see Note 12 – *Shareholders' Equity and Redeemable Preferred Stock).*

**NOTE 12 - SHAREHOLDERS' EQUITY AND REDEEMABLE PREFERRED STOCK**

***Preferred Stock Issuance***

On January 30, 2018, the Company entered into a Securities Purchase Agreement (the "Securities Purchase Agreement") by and among the Company and certain private funds affiliated with Värde (the "Purchasers"), pursuant to which the Company agreed to issue and sell to the Purchasers, and the Purchasers agreed to purchase from the Company, 100,000 shares of a newly created series of preferred stock of the Company, designated as "Series C 9.75% Convertible Participating Preferred Stock"(the **"**Series C Preferred Stock"), for a purchase price of $1,000 per share, or an aggregate of $100.0 million. Värde is the lead lender, and certain private funds affiliated with Värde are lenders, under the Company's Second Lien Credit Agreement (as defined above in *Note 9 – Long Term Debt*).

Closing of the issuance and sale of the shares of Series C Preferred Stock pursuant to the Securities Purchase Agreement occurred on January 31, 2018.

The terms of the Series C Preferred Stock are set forth in the Certificate of Designation for the Series C Preferred Stock (the "Certificate of Designation") filed by the Company with the Secretary of State of the State of Nevada on January 31, 2018. The following is a description of the material terms of the Series C Preferred Stock and the Securities Purchase Agreement. Series C Preferred Stock were not designated as Series C-1 4.75% Convertible Participating Preferred Stock, see Note 18, *Subsequent Events.*

*Ranking*. The Series C Preferred Stock ranks senior to the common stock with respect to dividends and rights on the liquidation, dissolution or winding up of the Company.

*Dividends*. Holders of shares of Series C Preferred Stock are entitled to receive cumulative preferential dividends, payable and compounded quarterly in arrears on January 1, April 1, July 1 and October 1 of each year, commencing April 1, 2018, at an annual rate of 9.75% of the Stated Value (as defined below) until April 26, 2021, after which the annual dividend rate will increase to 12.00% if paid in full in cash or 15.00% if not paid in full in cash. Dividends are payable, at the Company's option, (i) in cash, (ii) in kind by increasing the Stated Value by the amount per share of the dividend, or (iii) in a combination thereof. In addition to these preferential dividends, holders of shares of Series C Preferred Stock will be entitled to participate in any dividends paid on the common stock on an as-converted basis. As of September 30, 2018, the Company had $6.5 million of dividends in arrears on the Series C Preferred Stock. These dividends have not been declared by the Company's Board of Directors.

*Optional Redemption*. The Company has the right to redeem the Series C Preferred Stock, in whole or in part, at any time (subject to certain limitations on partial redemptions), at a price per share equal to (i) the Stated Value then in effect multiplied by (a) 120% if redeemed during 2018, (b) 125% if redeemed during 2019 or (c) 130% if redeemed after 2019, plus (ii) accrued and unpaid dividends thereon and any other amounts payable by the Company in respect thereof (the "Optional Redemption Amount"). The Series C Preferred Stock is perpetual and is not mandatorily redeemable at the option of the holders, except upon the occurrence of a Change of Control (as defined in the Certificate of Designation) as described below.

*Conversion*. Each share of Series C Preferred Stock is convertible at any time at the option of the holder into a number of shares of common stock equal to (i) the applicable Optional Redemption Amount divided by (ii) a conversion price of $6.15, subject to adjustment (the "Series C Preferred Stock Conversion Price"). The Series C Preferred Stock Conversion Price will be subject to proportionate adjustment in connection with stock splits and combinations, dividends paid in stock and similar events affecting the outstanding common stock. Additionally, the Series C Preferred Stock Conversion Price will be adjusted, based on a broad-based weighted average formula, if the Company issues, or is deemed to issue, additional shares of common stock for consideration per share that is less than the lesser of (i) $5.25 and (ii) the Series C Preferred Stock Conversion Price then in effect, subject to certain exceptions and to the Share Cap (as defined below).

The Company has the right to force the conversion of any or all of the outstanding shares of Series C Preferred Stock if (i) the volume-weighted average price per share of the common stock on the principal exchange on which it is then traded has been at least 140% of the Series C Preferred Stock Conversion Price then in effect for at least 20 of the 30 consecutive trading days immediately preceding the exercise by the Company of the forced conversion right and (ii) certain trading and other conditions are satisfied.

*Change of Control*. Upon the occurrence of a Change of Control (as defined in the Certificate of Designation), each holder of shares of Series C Preferred Stock will have the option to:

- cause the Company to redeem all of such holder's shares of Series C Preferred Stock for cash in an amount per share equal to (i) the Optional Redemption Amount plus (ii) 2.5% of the Stated Value, in each case as in effect immediately prior to the Change of Control;
- convert all of such holder's shares of Series C Preferred Stock into the number of shares of common stock into which such shares are convertible immediately prior to the Change of Control; or
- continue to hold such holder's shares of Series C Preferred Stock, subject to any adjustments to the Series C Preferred Stock Conversion Price or the number and kind of securities or other property issuable upon conversion resulting from the Change of Control and to the Company's or its successor's optional redemption rights described above.

*Liquidation Preference*. Upon any liquidation, dissolution or winding up of the Company, holders of shares of Series C Preferred Stock will be entitled to receive, prior to any distributions on the common stock or other capital stock of the Company ranking junior to the Series C Preferred Stock, an amount per share of Series C Preferred Stock equal to the greater of (i) the Optional Redemption Amount then in effect and (ii) the amount such holder would receive in respect to the number of shares of common stock into which a share of Series C Preferred Stock is then convertible.

*Voting Rights; Negative Covenants*. In addition to the Board designation rights described in the Certificate of Designation, holders of shares of Series C Preferred Stock will be entitled to vote with the holders of shares of common stock, as a single class, on all matters submitted for a vote of holders of shares of common stock. When voting together with the common stock, each share of Series C Preferred Stock will entitle the holder to a number of votes equal to (i) the Stated Value as of the applicable record date or other determination date divided by (ii) $4.42 (the closing price of the common stock on the NYSE American on January 30, 2018).

***Common Stock Repurchase***

In March 2018, the Company entered into a share-repurchase agreement (the "SRA") with an investment brokerage company ("Broker") to repurchase $1.0 million of the Company's common stock as part of the Share Repurchase Plan (the "Plan"). Under the terms of the SRA, the Company paid cash directly to the Broker and received delivery of shares of the Company's common stock. All of the shares acquired by the Company under the SRA are recorded as treasury stock. For the nine months ended September 30, 2018, the Company purchased 253,598 shares of the Company's common stock for approximately $1.0 million.

***Warrants***

The following table provides a summary of the Company's warrant activity for the nine months ended September 30, 2018:

| | Warrants | Weighted-Average Exercise Price |
|---|---|---|
| Outstanding at January 1, 2018 | 11,882,800 | $ 3.46 |
| Exercised | (3,975,957) | $ 2.21 |
| Expired or canceled | (2,769,514) | $ 3.38 |
| Outstanding at September 30, 2018 | 5,137,329 | $ 3.80 |

**NOTE 13 - SHARE BASED AND OTHER COMPENSATION**

The Company's share-based compensation consisted of the following (dollars in thousands):

| | Nine Months Ended September 30, 2018 | | | Nine Months Ended September 30, 2017 | | |
|---|---|---|---|---|---|---|
| | Stock Options | Restricted Stock | Total | Stock Options | Restricted Stock | Total |
| Share-based compensation expensed | $ 1,796 | $ 5,858 | $ 7,654 | $ 6,550 | $ 7,927 | $ 14,477 |
| Unrecognized share-based compensation costs | $ 970 | $ 5,069 | $ 6,039 | $ 5,217 | $ 1,133 | $ 6,350 |
| Weighted average amortization period remaining (in years) | 0.44 | 0.50 | | 0.75 | 0.68 | |

*Restricted Stock*

A summary of restricted stock grant activity pursuant to the Lilis 2012 Omnibus Incentive Plan (the "2012 Plan") and the 2016 Omnibus Incentive Plan (the "2016 Plan") for the nine months ended September 30, 2018, is presented below:

| | Number of Shares | Weighted Average Grant Date Price |
|---|---|---|
| Outstanding at January 1, 2018 | 2,475,266 | $ 4.22 |
| Granted | 1,134,944 | $ 4.60 |
| Vested and issued | (1,095,099) | $ (2.98) |
| Forfeited or canceled [1] | (971,145) | $ (4.26) |
| Outstanding at September 30, 2018 | 1,543,966 | $ 4.75 |

[1] Forfeitures are accounted for as and when incurred.

*Restricted Stock Units*

A summary of restricted stock unit grant activity pursuant to the 2012 Plan for the nine months ended September 30, 2018, is presented below:

| | Number of Shares | Weighted Average Grant Date Price |
|---|---|---|
| Outstanding at January 1, 2018 | 9,999 | $ 6.57 |
| Vested and issued | (9,999) | $ (6.57) |
| Outstanding at September 30, 2018 | — | $ — |

*Stock Options*

A summary of stock option activity pursuant to the 2016 Plan for the nine months ended September 30, 2018, is presented below:

| | | | Stock Options Outstanding and Exercisable | |
|---|---|---|---|---|
| | Number of Options | Weighted Average Exercise Price | Number of Options Vested/ Exercisable | Weighted Average Remaining Contractual Life (Years) |
| Outstanding at January 1, 2018 | 7,305,000 | $ 3.74 | 3,534,484 | 8.9 |
| Granted | 352,500 | $ 4.07 | — | — |
| Exercised | (1,049,150) | $ (2.06) | — | — |
| Forfeited or canceled [(1)] | (1,508,900) | $ (4.20) | — | — |
| Outstanding at September 30, 2018 | 5,099,450 | $ 3.83 | 3,128,033 | 6.8 |

[(1)] Forfeitures are accounted for as and when incurred.

During the nine months ended September 30, 2018, options to purchase 352,500 shares of the Company's common stock were granted under the 2016 Plan. The weighted average fair value of these options was $4.07. During the nine months ended September 30, 2018, the Company received $2.6 million from the exercise of vested stock options.

The fair value of stock option awards is determined using the Black-Scholes-Merton option-pricing model based on several assumptions. These assumptions are based on management's best estimate at the time of grant. The Company used the following weighted average of each assumption based on the grants in each fiscal year:

| | 2018 |
|---|---|
| Expected Term in Years | 6 |
| Expected Volatility | 58.8% - 72.6% |
| Expected Dividends | —% |
| Risk-Free Interest Rate | 2.59% - 2.71% |

**NOTE 14 - LOSS PER COMMON SHARE**

The following table shows the computation of basic and diluted net loss per share for the three and nine months ended September 30, 2018 and 2017 *(in thousands)*:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Net loss | (2,856) | (6,237) | (21,818) | (38,139) |
| Less: dividends on redeemable preferred stock | — | — | — | (122) |
| Less: dividends and deemed dividends on Series B convertible preferred stock | — | — | — | (4,635) |
| Less: dividends on Series C convertible preferred stock | (2,410) | — | (6,527) | — |
| Net loss attributable to common stockholders | (5,266) | (6,237) | (28,345) | (42,896) |
| Weighted average common shares outstanding - basic | 64,572,104 | 50,785,588 | 60,082,902 | 40,596,281 |
| Net loss per common share – basic | $ (0.08) | $ (0.12) | $ (0.47) | $ (1.06) |
| **Numerator for diluted loss per share:** | | | | |
| Net loss attributable to common stockholders | $ (5,266) | $ (6,237) | $ (28,345) | $ (42,896) |
| Add: interest expense on convertible Second Lien Loans | 7,499 | — | — | — |
| Less: gain on fair value change of embedded derivatives associated with Second Lien Loan | (10,612) | — | — | — |
| Net loss attributable to common stockholders | $ (8,379) | $ (6,237) | $ (28,345) | $ (42,896) |
| **Denominator for diluted net loss per share:** | | | | |
| Weighted average number of common shares outstanding - basic | 64,572,104 | 50,785,588 | 60,082,902 | 40,596,281 |
| Dilution effect of if-converted Second Lien Loans | 24,137,977 | — | — | — |
| Weighted average number of common shares outstanding - diluted | 88,710,081 | 50,785,588 | 60,082,902 | 40,596,281 |
| **Net loss per share - diluted:** | | | | |
| Common shares (diluted) | $ (0.09) | $ (0.12) | $ (0.47) | $ (1.06) |

The Company excluded the following shares from the diluted loss per share calculations above because they were anti-dilutive for the three and nine months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Stock Options | 5,099,450 | 7,158,500 | 5,099,450 | 7,158,500 |
| Restricted Stock Units | — | 9,999 | — | 9,999 |
| Series C Preferred Stock | 20,807,726 | — | 20,807,726 | — |
| Stock Purchase Warrants | 5,137,329 | 12,523,045 | 5,137,329 | 12,523,045 |
| Conversion of Second Lien Loans | — | 13,572,950 | 24,143,977 | 13,572,950 |
| | 31,044,505 | 33,264,494 | 55,188,482 | 33,264,494 |

## NOTE 15 - SUPPLEMENTAL NON-CASH TRANSACTIONS

The following table presents the supplemental disclosure of cash flow information for the nine months ended September 30, 2018 and 2017:

| | Nine Months Ended September 30, 2018 | |
|---|---|---|
| | 2018 | 2017 |
| | ($ in thousands) | |
| Non-cash investing and financing activities excluded from the statement of cash flows: | | |
| Conversion of Series B Preferred Stock and accrued dividends to common stock | — | 14,865 |
| Fair value of warrants issued and repriced as debt discount | — | 1,031 |
| Common stock issued for acquisition of oil and gas properties | 24,778 | — |
| Common stock issued for commitment fees associated with Private Placement | — | 250 |
| Cashless exercise of warrants | 356 | 371 |
| Change in capital expenditures for drilling costs in accrued liabilities | 17,313 | 5,632 |
| Accrued dividends for Series C Preferred Stock | 6,527 | — |
| Change in asset retirement obligations | 380 | 99 |
| Issuance of common stock for drilling services | — | 97 |
| Deemed dividends on Series B 6% Convertible Preferred Stock associated with beneficial conversion features | — | 3,767 |

## NOTE 16 – SEGMENT INFORMATION

Operating segments are defined as components of an entity that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and are regularly evaluated by the chief operating decision maker for the purposes of allocating resources and assessing performance. The Company currently has only one reportable operating segment, which is oil and gas development, exploration and production for which the Company has a single management team that allocates capital resources to maximize profitability and measures financial performance as a single entity.

## NOTE 17 - COMMITMENTS AND CONTINGENCIES

*Firm Oil Takeaway and Pricing Agreement*

On July 25, 2018,. the Company executed a five-year agreement with SCM Water to secure firm takeaway pipeline capacity and pricing on a long-haul pipeline to the Gulf Coast region commencing July 1, 2019. The agreement guarantees 6,000 Bbl/d of firm takeaway capacity on a long-haul pipeline to Corpus Christi, Texas at a specified price, beginning July 1, 2019 and continuing through June 30, 2020, and then 5,000 Bbl/d from July 1, 2020 through June 30, 2024. Pursuant to the agreement, The Company will also have the ability to increase capacity subject to availability by SCM Water. Further, SCM Water has agreed to purchase crude from the Company at a specified Magellan East Houston price with a fixed “differential basis,” providing price relief versus current market conditions.

*Environmental and Governmental Regulation*

As of September 30, 2018, there were no known environmental or regulatory matters which are reasonably expected to result in a material liability to the Company. Many aspects of the oil and natural gas industry are extensively regulated by federal, state, and local governments and regulatory agencies in all areas in which the Company has operations. Regulations govern such things as drilling permits, environmental protection and air emissions/pollution control, spacing of wells, the unitization and pooling of properties, reports concerning operations, land use, and various other matters including taxation. Oil and natural gas industry legislation and administrative regulations are periodically changed for a variety of political, economic, and other reasons. As of September 30, 2018, the Company had not been fined or cited for any violations of governmental regulations that would have a material adverse effect on the financial condition of the Company.

*Legal Proceedings*

The Company may from time to time be involved in various legal actions arising in the ordinary course of business. In the opinion of management, the Company's liability, if any, in these pending actions would not have a material adverse effect on the financial position of the Company. The Company's general and administrative expenses would include amounts incurred to resolve claims made against the Company.

The Company believes there is no litigation pending that could have, individually or in the aggregate, a material adverse effect on its results of operations or financial condition.

**NOTE 18 - SUBSEQUENT EVENTS**

*Senior Secured Revolving Credit Agreement*

On October 10, 2018, the Company entered into a five-year, $500 million senior secured revolving credit agreement (the "Revolving Credit Agreement"), by and among the Company, as borrower, certain subsidiaries of the Company, as guarantors (the "Revolving Credit Agreement Guarantors"), BMO Harris Bank, N.A., as administrative agent, and the lenders party thereto. The Revolving Credit Agreement provides for a senior secured reserve based revolving credit facility with an initial borrowing base of $95 million. The borrowing base is subject to semiannual re-determinations in May and November of each year. Borrowings under the Revolving Credit Agreement bear interest at a floating rate of either LIBOR or a specified base rate plus a margin determined based upon the usage of the borrowing base (subject to a 1% floor). The Company is required to pay a commitment fee of 0.5% per annum on any unused portion of the borrowing base. The Company's obligations under the Revolving Credit Agreement are secured by first priority liens on substantially all of the Company's and the Revolving Credit Agreement Guarantors' assets and are unconditionally guaranteed by each of the Revolving Credit Agreement Guarantors.

The Company borrowed $60 million under the Revolving Credit Agreement at closing, leaving $35 million initially available for future borrowing. The Company used the initial borrowings to repay in full and retire the Company's previously existing $50 million first lien credit facility (the credit agreement for which was amended and restated by the Revolving Credit Agreement), including accrued interest and a prepayment premium, and to pay transaction expenses. The Revolving Credit Agreement also provides for issuance of letters of credit in an aggregate amount up to $5.0 million.

The Revolving Credit Agreement matures on the earlier of the fifth anniversary of the closing date and the date that is 180 days prior to the maturity date of the Company's Second Lien Credit Agreement (as defined below). Borrowings under the Revolving Credit Agreement are subject to mandatory repayment with the net proceeds of certain asset sales and debt incurrences or if a borrowing base deficiency occurs. The Company also may voluntarily repay borrowings from time to time and, subject to the borrowing base limitation and other customary conditions, may re-borrow amounts that are voluntarily repaid. Mandatory and voluntary repayments generally will be made without premium or penalty. The Revolving Credit Agreement contains certain customary representations and warranties and affirmative and negative covenants, including covenants relating to: maintenance of books and records; financial reporting and notification; compliance with laws; maintenance of properties and insurance; and limitations on incurrence of indebtedness, liens, fundamental changes, international operations, asset sales, certain debt payments and amendments, restrictive agreements, investments, dividends and other restricted payments and hedging. It also requires the Company to maintain a ratio of Total Debt to EBITDAX (each as defined in the Revolving Credit Agreement) of not more than 4.00 to 1.00 and a ratio of current assets to current liabilities of not less than 1.00 to 1.00. The Revolving Credit Agreement also provides for events of default, including failure to pay any principal, interest or other amounts when due, failure to perform or observe covenants, cross-default on certain outstanding debt obligations, inaccuracy of representations and warranties, certain events under the Employee Retirement Income Security Act of 1974 ("ERISA"), change of control, the security documents or guaranty ceasing to be effective, and bankruptcy or insolvency events, subject to customary cure periods. Amounts owed by the Company under the Revolving Credit Agreement could be accelerated and become immediately due and payable following the occurrence an event of default.

*Second Lien Amendment*

On October 10, 2018, the Company entered into a sixth amendment (the "Second Lien Amendment") to its existing Second Lien Credit Agreement. Among other matters, the Second Lien Amendment amended the Second Lien Credit Agreement to permit the Company to enter into and incur indebtedness under the Revolving Credit Agreement and to provide for the reduction in the principal amount of the term loan under the Second Lien Credit Agreement pursuant to the Transaction Agreement (as defined and described below).

*Transaction Agreement*

On October 10, 2018, the Company entered into a Transaction Agreement (the "Transaction Agreement") by and among the Company and certain private funds affiliated with Värde Partners, Inc. (the "Värde Parties"), pursuant to which the Company agreed to:

- issue to the Värde Parties (i) an aggregate of 5,952,763 shares of the Company's common stock, which includes 5,802,763 shares of common stock at an exchange price of $5.00 per share of common stock plus an additional 150,000 shares of common stock, and (ii) 39,254 shares of a newly created series of preferred stock of the Company, designated as "Series D 8.25% Convertible Participating Preferred Stock" (the "Series D Preferred Stock"), as consideration for the reduction by approximately $56.3 million of the outstanding principal amount of the term loan under the Second Lien Credit Agreement, together with accrued and unpaid interest and the make-whole amount thereon totaling approximately $11.9 million; and
- issue and sell to the Värde Parties 25,000 shares of a newly created subseries of the Company's Series C 9.75% Convertible Participating Preferred Stock, designated as "Series C-2 9.75% Convertible Participating Preferred Stock" (the "Series C-2 Preferred Stock"), for a purchase price of $1,000 per share, or an aggregate of $25 million.

Closing of the issuance of the shares of common stock and Series D Preferred Stock and the issuance and sale of the shares of Series C-2 Preferred Stock pursuant to the Transaction Agreement occurred on October 10, 2018. Pursuant to an Amended and Restated Certificate of Designation of Preferences, Rights and Limitations of Series C-1 9.75% Convertible Participating Preferred Stock and Series C-2 9.75% Convertible Participating Preferred Stock (the "Series C Certificate of Designation"), filed by the Company with the Secretary of State of Nevada on October 10, 2018, the outstanding 100,000 shares of the Company's Series C 9.75% Convertible Participating Preferred Stock were re-designated as "Series C-1 9.75% Convertible Participating Preferred Stock" (the "Series C-1 Preferred Stock" and, together with the Series C-2 Preferred Stock, the "Series C Preferred Stock"). The Series C Preferred Stock and the Series D Preferred Stock are referred to collectively as the "Preferred Stock."

The terms of the Series D Preferred Stock are set forth in a Certificate of Designation of Preferences, Rights and Limitations of Series D Convertible Participating Preferred Stock (the "Series D Certificate of Designation" and, together with the Series C Certificate of Designation, the "Certificates of Designation"), filed by the Company with the Secretary of State of the State of Nevada on October 10, 2018. The following is a description of the material terms of the Series C Preferred Stock, the Series D Preferred Stock and the Transaction Agreement.

*Ranking*. The Series D Preferred Stock ranks senior to the Series C Preferred Stock, and the Series C Preferred Stock ranks senior to the common stock, with respect to dividends and rights on the liquidation, dissolution or winding up of the Company.

*Stated Value*. Each series of the Preferred Stock has a per share stated value of $1,000, subject to increase in connection with the payment of dividends in kind as described below (the "Stated Value").

*Dividends*. Holders of the Series C Preferred Stock and the Series D Preferred Stock are entitled to receive cumulative preferential dividends, payable and compounded quarterly in arrears on January 1, April 1, July 1 and October 1 of each year, at an annual rate of 9.75% of the Stated Value for the Series C Preferred Stock and 8.25% of the Stated Value for the Series D Preferred Stock until April 26, 2021, after which the annual dividend rate for each series will increase to 12.00% if paid in full in cash or 15.00% if not paid in full in cash. Dividends are payable, at the Company's option, (i) in cash, (ii) in kind by increasing the Stated Value by the amount per share of the dividend or (iii) in a combination thereof. Dividends payable to holders of the Series C-2 Preferred Stock and the Series D Preferred Stock will commence January 1, 2019. In addition to these preferential dividends, holders of the Preferred Stock will be entitled to participate in dividends paid on the common stock on an as-converted basis.

*Optional Redemption*. The Company has the right to redeem the Series C Preferred Stock, in whole or in part at any time (subject to certain limitations on partial redemptions), at a price per share equal to (i) the Stated Value then in effect multiplied by (a) 120% if redeemed during 2018, (b) 125% if redeemed during 2019 or (c) 130% if redeemed after 2019, plus (ii) accrued and unpaid dividends thereon and any other amounts payable by the Company in respect thereof (the "Series C Optional Redemption Price"). The Company has the right to redeem the Series D Preferred Stock, in whole or in part at any time (subject to certain limitations on partial redemptions), at a price per share equal to (i) the Stated Value then in effect multiplied by 117.5%, plus (ii) accrued and unpaid dividends thereon and any other amounts payable by the Company in respect thereof (the "Series D Optional Redemption Price" and, together with the Series C Operational Redemption Price, the respective "Optional Redemption Prices"). Each series of the Preferred Stock is perpetual and is not mandatorily redeemable at the option of the holders, except upon the occurrence of a Change of Control (as defined in the Certificates of Designation) as described below.

*Conversion*. Each share of Series C Preferred Stock is convertible at any time at the option of the holder into a number of shares of common stock equal to (i) the applicable Series C Optional Redemption Price divided by (ii) a conversion price of $6.15, subject to adjustment (the “Series C Conversion Price”). Each share of Series D Preferred Stock is convertible at any time at the option of the holder into a number of shares of common stock equal to (i) the Series D Optional Redemption Price divided by (ii) a conversion price of $5.50, subject to adjustment (the “Series D Conversion Price” and, together with the Series C Conversion Price, the “Conversion Prices”). The Conversion Prices will be subject to proportionate adjustment in connection with stock splits and combinations, dividends paid in stock and similar events affecting the outstanding common stock. Additionally, the Conversion Prices will be adjusted, based on a broad-based weighted average formula, if the Company issues, or is deemed to issue, additional shares of common stock for consideration per share that is less than the lesser of (i) $5.25 and (ii) the applicable Conversion Price then in effect, subject to certain exceptions and to the applicable Share Caps (as defined below). The Company has the right to force the conversion of any or all of the outstanding shares of each series of the Preferred Stock if (i) the volume-weighted average price per share of the common stock on the principal exchange on which it is then traded has been at least 140% of the applicable Conversion Prices then in effect for at least 20 of the 30 consecutive trading days immediately preceding the exercise by the Company of the forced conversion right and (ii) certain trading and other conditions are satisfied.

To comply with rules of the NYSE American (on which the common stock is traded), the Certificates of Designation provide that the number of shares of common stock issuable on conversion of a share of Preferred Stock may not exceed (i) in the case of the Series C-1 Preferred Stock (a) the Stated Value divided by (b) $4.42 (which was the closing price of the common stock on the NYSE American on January 30, 2018) (the “C-1 Share Cap”) or (ii) in the case of the Series C-2 Preferred Stock and the Series D Preferred Stock (a) the Stated Value divided by (b) $4.41 (which was the closing price of the common stock on the NYSE American on October 9, 2018) (together with the C-1 Share Cap, the “Share Caps”), in each case prior to the receipt of shareholder approval of the issuance of shares of common stock in excess of the applicable Share Caps upon conversion of shares of Preferred Stock of the applicable series. The Transaction Agreement requires the Company to seek such shareholder approval at its next annual meeting of shareholders. Accordingly, the Company intends to seek such shareholder approval at its 2019 annual meeting of shareholders.

*Change of Control*. Upon the occurrence of a Change of Control (as defined in the Certificates of Designation), each holder of shares of Preferred Stock will have the option to:

- cause the Company to redeem all of such holder’s shares of Preferred Stock for cash in an amount per share equal to (i) the applicable Optional Redemption Amount plus (ii) 2.5% of the Stated Value, in each case as in effect immediately prior to the Change of Control;
- convert all of such holder’s shares of Preferred Stock into the number of shares of common stock into which such shares are convertible immediately prior to the consummation of such Change of Control; or
- continue to hold such holder’s shares of Preferred Stock, subject to any adjustments to the applicable Conversion Price or the number and kind of securities or other property issuable upon conversion resulting from the Change of Control and to the Company’s or its successor’s optional redemptions rights described above.

*Liquidation Preference*. Upon any liquidation, dissolution or winding up of the Company:

- holders of shares of Series D Preferred Stock will be entitled to receive, prior to any distributions on the Series C Preferred Stock, the common stock or other capital stock of the Company ranking junior to the Series D Preferred Stock, an amount per share of Series D Preferred Stock equal to the greater of (i) the Series D Optional Redemption Price then in effect and (ii) the amount such holder would receive in respect of the number of shares of common stock into which such share of Series D Preferred Stock is then convertible; and
- holders of shares of Series C Preferred Stock will be entitled to receive, prior to any distributions on the common stock or other capital stock of the Company ranking junior to the Series C Preferred Stock, an amount per share of Series C Preferred Stock equal to the greater of (i) the applicable Series C Optional Redemption Price then in effect and (ii) the amount such holder would receive in respect of the number of shares of common stock into which such share of Series C Preferred Stock is then convertible.

*Board Designation Rights*. The Series C Certificate of Designation provides that holders of shares of Series C Preferred Stock will have the right, voting separately as a class, to designate (i) two members of the Company’s board of directors (the “Board”) for as long as the shares of common stock issuable on conversion of the outstanding shares of Series C Preferred Stock represent at least 15% of the outstanding shares of common stock (giving effect to conversion of all outstanding shares of Series C Preferred Stock) and (ii) one member of the Board for as long as the shares of common stock issuable on conversion of the outstanding shares of Series C Preferred Stock represent at least 7.5% of the outstanding shares of common stock (giving effect to conversion of all outstanding shares of Series C Preferred Stock). The Series D Certificate of Designation provides that holders of Series D Preferred Stock will have the right, voting separately as a class, to designate one member of the Board for as long as the shares of common stock issuable on conversion of the outstanding shares of Series D Preferred Stock represent at least 7.5%

of the outstanding shares of common stock (giving effect to conversion of all outstanding shares of Series D Preferred Stock); provided, however, that the holders of Series D Preferred Stock will not be entitled to designate a member of the Board so long as the holders of Series C Preferred Stock have the right to designate two members of the Board.

The Transaction Agreement separately grants to the Värde Parties substantially identical rights to appoint members of the Board as long as the Värde Parties and their affiliates beneficially own (as defined in Rule 13d-3 under the Securities Exchange Act of 1934, as amended) shares of common stock issued or issuable upon conversion of shares of Preferred Stock representing the 15% and 7.5% thresholds of the outstanding common stock described above. However, the number of members of the Board the Värde Parties have the right to designate under the Transaction Agreement will be reduced by the number of Directors that holders of shares of Preferred Stock have the right to appoint under the Certificates of Designation.

The Board members designated by holders of shares of Preferred Stock pursuant to the Certificates of Designation or by the Värde Parties pursuant to the Transaction Agreement must be reasonably acceptable to the Board and its Nominating and Corporate Governance Committee, acting in good faith, but any investment professional of Värde Parties, Inc. or its affiliates will be deemed to be reasonably acceptable. In addition, such Board designees must satisfy applicable SEC and stock exchange requirements and comply with the Company's corporate governance guidelines.

*Voting Rights; Negative Covenants*

In addition to the Board designation rights described above, holders of shares of each series of Preferred Stock will be entitled to vote with the holders of shares of common stock, as a single class, on all matters submitted for a vote of holders of shares of common stock. When voting together with the common stock, each share of Preferred Stock will entitle the holder to a number of votes equal to (i) the applicable Stated Value as of the applicable record date or other determination date divided by (ii) (a) in the case of Series C-1 Preferred Stock, $4.42 (the closing price of the common stock on the NYSE American on January 30, 2018), and (b) in the case of Series C-2 Preferred Stock and Series D Preferred Stock, $4.41 (the closing price of the common stock on the NYSE American on October 9, 2018).

Each of the Certificates of Designation provides that, as long as any shares of Series C Preferred Stock or Series D Preferred Stock, as applicable, are outstanding, the Company may not, without the prior affirmative vote or prior written consent of the holders of a majority of the outstanding shares of the Series C Preferred Stock or the Series D Preferred Stock, as applicable:

- amend the Company's articles of incorporation or bylaws in any manner that materially and adversely affects any rights, preferences, privileges or voting powers of the applicable series of Preferred Stock or holders of shares of such series of Preferred Stock;
- issue, authorize or create, or increase the issued or authorized amount of, the applicable series of Preferred Stock, any class or series of capital stock ranking senior to or in parity with such series of Preferred Stock, or any security convertible into or evidencing the right to purchase any shares of such series of Preferred Stock or any such senior or parity securities, other than equity, the proceeds of which, are used to immediately redeem all of the outstanding shares of Preferred Stock of the applicable series pursuant to the Company's optional redemption rights described above;
- subject to certain exceptions, declare or pay any dividends or distributions on, or redeem or repurchase, or permit any of its controlled subsidiaries to redeem or repurchase, shares of common stock or any other shares of capital stock of the Company ranking junior to the applicable series Preferred Stock, subject to certain exceptions;
- authorize, issue or transfer, or permit any of its controlled subsidiaries to authorize, issue or transfer, any equity (including any obligation or security convertible into, exchangeable for or evidencing the right to purchase any such equity) in any subsidiary of the Company other than (i) equity issued or transferred to the Company or another wholly-owned subsidiary of the Company or (ii) equity, the proceeds of which, are used to immediately redeem all of the outstanding shares of the applicable series of Preferred Stock pursuant to the Company's optional redemption rights described above; or
- subject to certain exceptions, modify the number of directors constituting the entire Board at any time when holders of shares of the applicable series Preferred Stock have the right to designate a member of the Board.

The Certificates of Designation further provide that, in the case of the Series C Preferred Stock, as long as shares of Series C Preferred Stock having an aggregate Series C Optional Redemption Price of at least $50 million are outstanding, and in the case of the Series D Preferred Stock, as long as shares of Series D Preferred Stock having an aggregate Series D Optional Redemption Price of at least $19.65 million are outstanding, the Company may not, and may not permit any of its controlled subsidiaries to, without the prior affirmative vote or prior written consent of the holders of a majority of the outstanding shares of the applicable series of Preferred Stock:

- subject to certain exceptions, incur indebtedness or permit to exist any liens on the assets or properties of the Company or its subsidiaries;
- enter into, adopt or agree to any "restricted payment" or similar provision that restricts or limits the payment of dividends on, or the redemption of, shares of the applicable series of Preferred Stock under any credit facility, indenture or other similar instrument of the Company that would be more restrictive on the payment of dividends on, or redemption of, shares of the applicable series of Preferred Stock other than those existing as of the date on which shares of the applicable series of Preferred Stock were first issued;
- liquidate or dissolve the Company;
- enter into any material new line of business or fundamentally change the nature of the Company's business, including any acquisition of oil and gas properties outside the Permian Basin; or
- enter into certain transactions with affiliates of the Company unless made on an arm's-length basis and approved by a majority of the disinterested members of the Board.

*Transfer Restrictions*. The Certificates of Designation provide that shares of Series C-2 Preferred Stock and Series D Preferred Stock and shares of common stock issued on conversion of shares of the respective Preferred Stock may not be transferred by the holder of such shares, other than to an affiliate of such holder, prior to April 10, 2019. On and after April 10, 2019, such shares will be freely transferable, subject to applicable securities laws.

*Other Terms*. The Transaction Agreement contains other terms, including representations, warranties and covenants, that are customary for a transaction of this sort.

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

*The following discussion and analysis of our financial condition and results of operations should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report, as well as the unaudited financial statements and notes thereto included in this Quarterly Report on Form 10-Q. This discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of various factors including those set forth under Item "1A. Risk Factors." - in our Annual Report.*

***Overview***

We are an independent oil and natural gas company focused on the acquisition, development, and production of conventional and unconventional oil and natural gas properties in the core of the Delaware Basin in Winkler, Loving, and Reeves Counties, Texas and Lea County, New Mexico.

Production Update:

- In the third quarter ended September 30, 2018, Lilis' average reported daily sales volume was 5,588 BOE/d which equates to a 234% increase compared to the same quarter in 2017. Production was 5,937 BOE/d after giving pro forma effect to the working interest and acreage transaction that was closed October 16, 2018. Our estimated production capacity for the quarter ended September 30, 2018 exceeded 8,000 BOE/d considering weather, midstream, and construction shut-ins of approximately 2,104 BOE/d.

- The Company is maintaining its 2018 target exit rate of 8,000 Boe/d at this time while curtailments are being resolved. Moreover, the Company still expects significant increases in production from ongoing drilling program and longer lateral developments to be realized during the fourth quarter. Thus, management believes it will achieve current year-end guidance.

| | **Three Months Ended September 30, 2018** | **Nine Months Ended September 30, 2018** |
|---|---|---|
| | *(in BOE/d and Mcf/d)* | |
| **Sales volume:** | | |
| Oil (BOE/d) | 3,287 | 2,746 |
| Natural Gas (Mcf/d) | 9,314 | 7,390 |
| NGL (BOE/d) | 748 | 650 |
| **Total BOE/d** | 5,588 | 4,628 |
| **ADD:** | | |
| Shut-ins | 2,104 | 1,605 |
| **Production capacity BOE/d (1)** | 7,692 | 6,233 |

(1) Production capacity will be 8,041 BOE/d if 349 BOE/d production volume from the working interest and acreage transaction completed in October 2018 is included.

- Curtailments in the third quarter were primarily due to third-party equipment upgrades and construction on critical trunk lines that delayed connections for several wells, primarily in Lilis' eastern acreage. However, lines are now in place, pressure tested, and operational.

- Production from existing wells, which have not been curtailed, are tracking to expectations in the Delaware Basin.

Other Significant Third Quarter 2018 Highlights:

- Our third quarter shows a significant increase in revenue from oil and natural gas operations from $5.4 million during the three months ended September 30, 2017 to $19.5 million during the three months ended September 30, 2018. The increase of $14.1 million or 261% was primarily attributable to an increase in sales volume to 514,102 BOE during the three months ended September 30, 2018 from 154,078 BOE for the same period in 2017, as well as an increase in average realized oil and natural gas prices to $37.90 per BOE during the three months ended September 30, 2018 from $34.98 per BOE for the same period in 2017.

- We currently have production hedges on approximately 2,600 average BOE/d that yield an average floor of $58.13 and a ceiling of $65.79 for the remainder of 2018, and we have also placed several basis hedges on 1,500 Midland-Cushing BOE/d with an average cost differential of $5.62 for 2018.

- On July 25, 2018, we received an upfront payment of $10.0 million from Salt Creek Midstream LLC ("SCM") for an option to acquire our existing water infrastructure for the firm transportation and pricing for crude oil and a $5.0 million prefunded drilling bonus. Upfront payments plus possible drilling bonuses for the SCM option equal $20 million, of which $17.5 million was received by September 30, 2018. Additionally, we received $2.5 million on October 1, 2018 as a bonus for the grant of right-of-way/easement and will receive an additional $2.5 million bonus upon hitting the target of 40,000 barrels per day of produced water. As of October 1, 2018, we received a total of $52.5 million of non-diluted capital funds from SCM.

- The Company executed a five-year agreement to secure firm takeaway pipeline capacity and pricing on a long-haul pipeline to the Gulf Coast commencing July 1, 2019. The agreement guarantees 6,000 Bbl/d of firm capacity on a long-haul pipeline to Corpus Christi at a specified price, beginning July 1, 2019 through June 30, 2020, and 5,000 Bbl/d from July 1, 2020 through June 30, 2024. We will have firm takeaway and firm pricing commencing July 1, 2019, and the ability to increase capacity subject to availability by SCM. Further, SCM has agreed to purchase the crude from us at a specified Magellan East Houston price with a fixed “differential basis,” providing price relief versus current market conditions.

- During the third quarter of 2018, Lilis successfully drilled and completed 7 horizontal wells in Wolfcamp A, B, 2nd and 3rd Bone Spring formations. The Moose #1H (WCA), AG Hill #2H (2nd BS), and Axis #1H (WCB), are completed and flowing to sales. We spud the Tiger #3H (3rd BS), North West Axis #1 (WCA), Oso #1H (WCA), and the Haley #1H (WCA) in the third quarter of 2018.

***Results of Operations – For the Three and Nine Months Ended September 30, 2018 and 2017***

During the nine months ended September 30, 2018, we drilled or were in the process of drilling 15 gross (13.2 net) horizontal wells and completed or were in the process of completing 15 gross (13.9 net) horizontal wells. To date, we have successfully spud 13 wells and completed 12 wells in the Wolfcamp A, B and XY and Bone Spring, continuing the strategy of delineating and de-risking the acreage position both geographically and geologically. As of September 30, 2018, we have production flowing from our 22 horizontal wells and 13 legacy vertical wells with an estimated productive capacity of 7,692 net BOE/d.

During the twelve months following September 30, 2017, we have placed 16 gross (15.0 net) wells into production which significantly contributed to the net sales volume increase to 514,102 BOE and 1,263,241 BOE for the three and nine months ended September 30, 2018, respectively.

*Oil, natural gas and NGL sales*

The following table sets forth selected revenue and sales volume data for the three months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2018 | 2017 | Variance | % |
| **Net sales volume:** | | | | |
| Oil (Bbl) | 302,448 | 97,824 | 204,624 | 209 % |
| Natural gas (Mcf) | 856,865 | 215,930 | 640,935 | 297 % |
| NGL (Bbl) | 68,844 | 20,266 | 48,578 | 240 % |
| Total (BOE) | 514,102 | 154,078 | 360,024 | 234 % |
| Average daily sales volume (BOE/d) | 5,588 | 1,675 | 3,913 | 234 % |
| **Average realized sales price:** | | | | |
| Oil ($/Bbl) | $ 52.82 | $ 44.75 | $ 8.07 | 18 % |
| Natural gas ($/Mcf) | $ 1.79 | $ 2.74 | $ (0.95) | (35)% |
| NGL ($/Bbl) | $ 28.59 | $ 20.72 | $ 7.86 | 38 % |
| Total ($/BOE) | $ 37.90 | $ 34.98 | $ 2.91 | 8 % |
| **Oil, natural gas and NGL revenues** *(in thousands):* | | | | |
| Oil revenue | $ 15,976 | $ 4,378 | $ 11,598 | 265 % |
| Natural gas revenue | 1,538 | 592 | 946 | 160 % |
| NGL revenue | 1,968 | 420 | 1,548 | 369 % |
| Total revenue | $ 19,482 | $ 5,390 | $ 14,092 | 261 % |

*Oil, natural gas and NGL sales.* For the three months ended September 30, 2018, oil, natural gas and NGL sales revenue increased by $14.1 million to $19.5 million, compared to $5.4 million for the same period during 2017. The increase in revenue was due primarily to higher oil, natural gas and NGL sales volumes in the three months ended September 30, 2018, compared to the same period in 2017. Total sales volume increased by 360,024 BOE to 514,102 BOE during the three months ended September 30, 2018, from 154,078 BOE during the same period in 2017. Higher realized oil and NGL prices of $52.82 and $28.59 per Bbl, respectively, also contributed to the increased revenues for the quarter.

Crude transportation costs are deducted from the Company's gross revenue. For the three months ended September 30, 2018, transportation costs increased by $1.3 million to $1.6 million compared to $0.2 million for the same period in 2017. With crude transportation provided for in the SCM Gathering Agreement, the Company expects to mitigate the trucking cost component of its realized oil prices in 2019. The Company expects savings of approximately $4.50 per Bbl or approximately 87.4% decrease in transportation costs utilizing pipe gathering as opposed to trucking.

The following table sets forth selected revenue and sales volume data for the nine months ended September 30, 2018 and 2017:

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2018 | 2017 | Variance | % |
| **Net sales volume:** | | | | |
| Oil (Bbl) | 749,659 | 243,369 | 506,290 | 208 % |
| Natural gas (Mcf) | 2,017,509 | 574,485 | 1,443,024 | 251 % |
| NGL (Bbl) | 177,331 | 54,743 | 122,588 | 224 % |
| Total (BOE) | 1,263,241 | 393,859 | 869,382 | 221 % |
| Average daily sales volume (BOE/d) | 4,627 | 1,443 | 3,184 | 221 % |
| **Average realized sales price:** | | | | |
| Oil ($/Bbl) | $ 57.12 | $ 45.36 | $ 11.76 | 26 % |
| Natural gas ($/Mcf) | $ 1.77 | $ 2.84 | $ (1.07) | (38)% |
| NGL ($/Bbl) | $ 28.02 | $ 20.24 | $ 7.78 | 38 % |
| Total ($/BOE) | $ 40.66 | $ 34.98 | $ 5.67 | 16 % |
| **Oil, natural gas and NGL revenues** *(in thousands):* | | | | |
| Oil revenue | $ 42,819 | $ 11,040 | $ 31,779 | 288 % |
| Natural gas revenue | 3,572 | 1,631 | 1,941 | 119 % |
| NGL revenue | 4,969 | 1,108 | 3,861 | 348 % |
| Total revenue | $ 51,360 | $ 13,779 | $ 37,581 | 273 % |

*Oil, natural gas and NGL sales.* For the nine months ended September 30, 2018, oil, natural gas and NGL sales revenue increased by $37.6 million to $51.4 million, compared to $13.8 million for the same period during 2017. The increase of $37.6 million was due primarily to higher oil, natural gas and NGL sales volumes in the nine months ended September 30, 2018, compared to the same period in 2017. Total sales volume increased by 869,382 BOE to 1,263,241 BOE during the nine months ended September 30, 2018, from 393,859 BOE during the same period in 2017. Higher realized oil and NGL prices of $57.12 and $28.02 per Bbl, respectively, also contributed to the increased revenues for the nine months ended September 30, 2018.

Crude transportation costs are deducted from the Company's gross revenue. For the nine months ended September 30, 2018, transportation costs increased by $2.3 million to $2.9 million compared to $0.6 million for the same period in 2017. With crude transportation provided for in the SCM Gathering Agreement, the Company expects to mitigate the trucking cost component of its realized oil prices in 2019. The Company expects savings of approximately $4.50 per Bbl or approximately 87.4% decrease in transportation costs utilizing pipe gathering as opposed to trucking.

*Operating Expenses*

The following table shows a comparison of operating expenses for the three months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2018 | 2017 | Variance | % |
| **Operating Expenses per BOE:** | | | | |
| Production costs | $ 5.39 | 9.14 | $ (3.75) | (41)% |
| Gathering, processing and transportation | 1.87 | 2.63 | (0.76) | (29)% |
| Production and ad valorem taxes | 2.81 | 1.88 | 0.93 | 49 % |
| General and administrative | 6.98 | 37.97 | (30.99) | (82)% |
| General and administrative - non-cash & other transaction costs | 6.32 | 33.05 | (26.73) | (81)% |
| Depreciation, depletion, amortization and accretion | 13.95 | 9.37 | 4.58 | 49 % |
| Total operating expenses per BOE | $ 37.32 | $ 94.04 | $ (56.72) | (60)% |
| | | | | |
| **Operating Expenses:** | | | | |
| Production costs | $ 2,772 | $ 1,409 | $ 1,363 | 97 % |
| Gathering, processing and transportation | 963 | 405 | 558 | 138 % |
| Production and ad valorem taxes | 1,446 | 290 | 1,156 | 399 % |
| General and administrative | 3,590 | 5,851 | (2,261) | (39)% |
| General and administrative - non-cash and other transaction costs | 3,248 | 5,092 | (1,844) | (36)% |
| Depreciation, depletion, amortization and accretion | 7,172 | 1,443 | 5,729 | 397 % |
| Total Operating Expenses | $ 19,191 | $ 14,490 | $ 4,701 | 32 % |

*Production costs.* Our production costs increased by $1.4 million, or 97%, to $2.8 million for the three months ended September 30, 2018 compared to $1.4 million for the three months ended September 30, 2017 due to an increase in production volumes. Our overall production cost per BOE decreased by $3.75, or 41%, from $9.14 per BOE for the three months ended September 30, 2017 to $5.39 for the three months ended September 30, 2018. The decrease in costs per BOE was mainly due to: (i) 45% decrease in salt water disposal costs, resulting in a cost reduction of $1.69 per BOE, (ii) a 99% decrease in testing costs, resulting in a cost reduction of $1.18 per BOE, and (iii) a 96% decrease in repair costs, resulting in a cost reduction of $0.51 per BOE, plus various other gained efficiencies. The Company expects to further reduce production costs with the SCM Water disposal agreement. The Company anticipates that a majority of its water will be disposed through the future water disposal system at a competitive gathering rate under the agreement.

*Gathering, processing and transportation.* Our gathering, processing and transportation costs increased by $0.6 million to $1.0 million for the three months ended September 30, 2018, compared to $0.4 million during the same period in 2017, due to higher sales volumes. The decrease in costs on a per BOE basis were the result of lower gathering and treating rates.

*Production and ad valorem taxes.* Production taxes were $1.4 million for the three months ended September 30, 2018, compared to $0.3 million for the same period in 2017, resulting in an increase of $1.1 million. Currently, ad valorem, severance and conservation taxes range from 1% to 13% based on the state and county from which production is derived. The significant increase in production taxes corresponds to the increase in production revenues during the three months ended September 30, 2018.

*Depreciation, depletion, amortization and accretion.* Our depreciation, depletion and amortization expense increased by $5.8 million to $7.2 million for the three months ended September 30, 2018, compared to $1.4 million during the same period in 2017. The increase was the result of a higher depletion rate of $13.95 per BOE and higher sales volumes of 514,102 BOE during the three months ended September 30, 2018, as compared to a depletion rate of $9.37 per BOE and sales volumes of 154,078 BOE for the same period in 2017. The depletion rate increase by 49% is primarily attributable to 45 PUD locations added to the full cost pool since September 30, 2017.

*General and administrative expenses.* General and administrative expenses ("G&A") decreased by $4.1 million to $6.8 million for the three months ended September 30, 2018, as compared to $10.9 million for the three months ended September 30, 2017. The decrease of $4.1 million in G&A was primarily attributable to a decrease of $0.5 million in payroll and other G&A related expenses, $3.0 million in stock-based compensation and $0.6 million in legal and professional fees. The G&A for the three months ended September 30, 2018 consisted of $1.7 million for payroll expense, $2.1 million of non-cash stock-based compensation, $1.3 million in legal and other professional fees and $1.7 million in other G&A related expenses.

Included in the $3.2 million of general and administrative - non-cash and other transaction costs for the three months ended September 30, 2018, are $2.1 million of stock-based compensation and $1.1 million of transaction costs associated with SCM Water transaction to acquire our existing water infrastructure for the firm transportation and pricing for crude oil as well as costs incurred on other acquisitions. For the three months ended September 30, 2017, the $5.1 million in general and administrative - non-cash expense includes only the stock-based compensation.

The following table shows a comparison of operating expenses for the nine months ended September 30, 2018 and 2017:

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2018 | 2017 | Variance | % |
| **Production Costs per BOE:** | | | | |
| Production costs | $ 6.75 | $ 8.47 | $ (1.72) | (20)% |
| Gathering, processing and transportation | $ 1.82 | $ 2.14 | $ (0.32) | (15)% |
| Production and ad valorem taxes | $ 2.85 | $ 1.80 | $ 1.05 | 58 % |
| General and administrative | $ 9.05 | $ 49.90 | $ (40.85) | (82)% |
| General and administrative - non-cash and other transaction costs | $ 10.49 | $ 42.20 | $ (31.71) | (75)% |
| Depreciation, depletion, amortization and accretion | $ 13.91 | $ 10.02 | $ 3.89 | 39 % |
| Total (BOE) | $ 44.87 | $ 114.53 | $ (69.66) | (61)% |
| **Operating Expenses:** | | | | |
| Production costs | $ 8,532 | $ 3,336 | $ 5,196 | 156 % |
| Gathering, processing and transportation | 2,297 | 842 | 1,455 | 173 % |
| Production and ad valorem taxes | 3,604 | 710 | 2,894 | 408 % |
| General and administrative | 12,664 | 20,847 | (8,183) | (39)% |
| General and administrative - non-cash and other transaction costs | 12,018 | 15,426 | (3,408) | (22)% |
| Depreciation, depletion, amortization and accretion | 17,572 | 3,946 | 13,626 | 345 % |
| Total Operating Expenses | $ 56,687 | 45,107 | 11,580 | 26 % |

*Production costs.* Our production costs increased by $5.2 million, or 156%, to $8.5 million for the nine months ended September 30, 2018, compared to $3.3 million for the nine months ended September 30, 2017, due to an increase in production volumes. Our overall production cost per BOE decreased by $1.72, or 20%, from $8.47 per BOE for the nine months ended September 30, 2017 to $6.75 for the nine months ended September 30, 2018. The decrease in costs per BOE was mainly due to: (i) a 91% decrease in repair costs, resulting in a cost reduction of $0.91 per BOE, (ii) a 94% decrease in testing costs, resulting in a cost reduction of $0.45 per BOE, and (iii) a 55% decrease in administrative overhead costs, resulting in a cost reduction of $0.28 per BOE, plus various other gained efficiencies. The Company expects to further reduce production cost with the SCM Water disposal agreement. The Company anticipates that the majority of its water will be disposed through the future water disposal system at a competitive gathering rate under the agreement.

*Gathering, processing and transportation.* Our gathering, processing and transportation costs increased by $1.5 million to $2.3 million for the nine months ended September 30, 2018, compared to $0.8 million during the same period in 2017, due to higher sales volumes. The decrease in costs on a per BOE basis were the result of lower gathering and treating rates.

*Production and ad valorem taxes.* Production taxes were $3.6 million for the nine months ended September 30, 2018, compared to $0.7 million for the same period in 2017, an increase of $2.9 million. Currently, ad valorem, severance and conservation taxes range from 1% to 13% based on the state and county from which production is derived. The increase in production taxes corresponds to the increase in production revenues during the nine months ended September 30, 2018.

*Depreciation, depletion, amortization and accretion.* Our depreciation, depletion and amortization expense increased by $13.6 million to $17.5 million for the nine months ended September 30, 2018, compared to $3.9 million during the same period in 2017.

The increase was the result of a higher depletion rate of $13.91 per BOE and higher sales volumes of 1,263,241 BOE during the nine months ended September 30, 2018, as compared to depletion rate of $10.02 per BOE and sales volumes of 393,859 BOE for the same period in 2017. The depletion rate increase by 39% is primarily attributable to 45 PUD locations added to the full cost pool since September 30, 2017.

*General and administrative expenses.* G&A decreased by $11.6 million to $24.7 million for the nine months ended September 30, 2018, as compared to $36.3 million for the nine months ended September 30, 2017. The decrease of $11.6 million in G&A was primarily attributable to decrease of $6.9 million in payroll and $6.8 million in non-cash stock-based compensation, offset by the increase of $2.1 million in legal and professional fees. The G&A for the nine months ended September 30, 2018, consisted of $6.8 million for payroll expense, $7.7 million of non-cash stock-based compensation, $6.6 million in legal and other professional fees and $3.6 million in other G&A related expenses.

Included in the $12.0 million of general and administrative - non-cash and other transaction costs during the nine months ended September, 2018, are $7.7 million of stock-based compensation and $4.3 million of transaction costs associated with SCM Midstream LLC transaction which includes an option to provide certain midstream services, and with SCM Water transactions which include an option to acquire our existing water infrastructure for the firm transportation and pricing for crude oil plus costs incurred on other acquisitions. For the nine months ended September 30, 2017, the $15.4 million of general administrative - non-cash and other transaction costs includes $14.5 million of non-cash stock-based compensation and $0.9 million of other transaction costs.

*Other Expenses*

The following table shows a comparison of other expenses for the three months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | **2018** | **2017** | **Variance** | **%** |
| | ***(In Thousands)*** | | | |
| Other income (expense): | | | | |
| Other income (expense) | $ 1 | $ 151 | $ (150) | (99)% |
| Loss from commodity derivatives, net | (4,811) | — | (4,811) | 100 % |
| Change in fair value of financial instruments | 10,612 | 6,368 | 4,244 | 67 % |
| Interest expense | (8,949) | (3,656) | (5,293) | 145 % |
| Total other income (expenses) | $ (3,147) | $ 2,863 | $ (6,010) | (210)% |

*Loss from Commodity Derivatives.* Oil price derivative transactions were entered into with counterparties effective October 2017. As a result of increases in oil prices since entering into the derivative transactions, we recorded a loss of $0.8 million on settlements and a loss of $4.0 million on unsettled positions as a result of the changes in fair value of the oil commodity derivatives during the three months ended September 30, 2018. During the three months ended September 30, 2017, we did not participate in any commodity derivative transactions.

*Change in Fair Value of Financial Instruments.* During the three months ended September 30, 2018 and 2017, the fair value change of $10.6 million and $6.4 million, respectively, included the fair value change of embedded derivatives for the convertible Second Lien Credit Agreement. The fair value change of $10.6 million recorded during the three months ended September 30, 2018 was primarily attributed to the decrease in the Company stock price from $5.20 per share at June 30, 2018, to $4.90 per share at September 30, 2018.

*Interest Expense.* Interest expense for the three months ended September 30, 2018 was $8.9 million compared to $3.7 million for the three months ended September 30, 2017. For the three months ended September 30, 2018, we incurred interest expense of $1.2 million for quarterly interest payments on the $50 million Riverstone First Lien Loans, $3.4 million of paid-in-kind ("PIK") interest and $4.1 million related to amortized debt discount on our Second Lien Loans and $0.2 million of amortized debt issuance costs. For the three months ended September 30, 2017, we incurred $0.2 million of interest expense and non-cash interest expense that included $1.9 million of PIK interest and $1.6 million of amortized debt discount.

The following table shows a comparison of other expenses for the nine months ended September 30, 2018 and 2017:

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2018 | 2017 | Variance | % |
| | (In Thousands) | | | |
| Other income (expense): | | | | |
| Other income (expense) | $ 2 | $ 19 | $ (17) | (89)% |
| Loss from commodity derivatives, net | (9,383) | — | (9,383) | 100 % |
| Change in fair value of financial instruments | 19,499 | 4,254 | 15,245 | 358 % |
| Interest expense | (26,609) | (11,084) | (15,525) | 140 % |
| Total other income (expenses) | $ (16,491) | $ (6,811) | $ (9,680) | 142 % |

*Loss from Commodity Derivatives.* Oil price derivative transactions were entered into with counterparties effective October 2017. As a result of increases in oil prices since entering into the derivative transactions, we recorded a loss of $7.3 million on settlements and a loss of $2.1 million on unsettled positions as a result of the changes in fair value of the oil commodity derivatives during the nine months ended September 30, 2018. During the nine months ended September 30, 2017, we did not participate in any commodity derivative transactions.

*Change in Fair Value of Financial Instruments.* During the nine months ended September 30, 2018, the fair value change of $19.5 million and the $4.3 million for the nine months ended September 30, 2017, included primarily the fair value change of embedded derivatives for the convertible Second Lien Credit Agreement. The fair value change of $19.5 million recorded during the nine months ended September 30, 2018 was primarily attributable to the decrease in the Company stock price from $5.11 per share at December 31, 2017 to $4.90 per share at September 30, 2018 and a lower discount rate used to estimate the fair value of the derivative due to the passage of time.

*Interest Expense.* Interest expense for the nine months ended September 30, 2018 was $26.6 million compared to $11.1 million for the months ended September 30, 2017. For the nine months ended September 30, 2018, we incurred interest expense of $3.1 million for interest payments on the $50 million Riverston First Lien Loans, $0.7 million on the Bridge Loan that was paid off during the first quarter of 2018, $9.8 million of PIK interest, $11.9 million related to amortized debt discount and $1.1 million of amortized debt issuance costs. For the nine months ended September 30, 2017, we incurred $1.1 million of interest payments and non-cash interest expense which included $3.3 million of PIK interest, $5.0 million related to amortized debt discount and $1.7 million of debt issuance costs.

***Capital Resources and Liquidity***

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions and investors, the sale of equity and equity derivative securities and asset dispositions. Our primary uses of capital have been utilized for the acquisition, development, exploration and exploitation of oil and natural gas properties, in addition to refinancing of debt instruments.

Based upon current commodity price expectations for 2018 and 2019, we believe that our cash flow from operations, and Revolving Credit Facility (the "RBL") availability, will be sufficient to fund our drilling and completion operations over the next 12 months, including working capital requirements. We expect to become cash flow neutral in 2019. However, future cash flows are subject to a number of variables, including uncertainty in forecasted production volumes and commodity prices. We are the operator for at least 90% of our 2018 operational capital program and, as a result, the amount and timing of a substantial portion of our capital expenditures is discretionary. We believe that our operation of the Company's properties will provide us with significant discretion over the pace and scale of spending for our 2019 capital program. Accordingly, we may determine it prudent to curtail drilling and completion operations due to capital constraints or reduced returns on investment in the event commodity prices decline.

Our existing financial position provides us with the financial flexibility to fund our currently planned 2018 and 2019 drilling program. On October 10, 2018, we:

- Entered into a five-year, $500 million senior secured RBL with an initial borrowing base of $95 million to repay our First Lien Term Loan with Riverstone (the “Riverstone First Lien Loans”). The RBL is expandable and reviewed semiannually in the spring and fall.

- Successfully negotiated the conversion of approximately $68.3 million of our existing Second Lien Loan due 2021.

- Enhanced liquidity by $60 million including $35 million in initial capacity under the RBL and $25 million raised in the announced Series C tack-on.

- Reduced our Second Lien Loan principal balance by approximately $56 million through the equity conversion.

- Reduced interest expense associated with the Riverstone First Lien Loans by 4.00 percent from LIBOR plus 6.75 percent to LIBOR plus 2.75 percent. Approximately $2.4 million in annual PIK interest expense savings was realized as a result of the portion of the Second Lien Loan which was converted to common equity.

On July 25, 2018, we entered into another infrastructure solution including a flow assurance agreement that provides the Company with a firm takeaway agreement and water gathering transactions. Total expected cash consideration for the water gathering and disposal infrastructure is $20.0 million. On July 25, 2018, the Company received an upfront payment of $10.0 million for the option to acquire our existing water infrastructure for the firm transportation and pricing for crude oil as well as a $5.0 million for prefunded drilling bonus. The Company received $2.5 million on October 1, 2018 as a bonus for the grant of right-of-way/easement and expects to receive $2.5 million bonus for hitting the target of 40,000 barrels per day of produced water in the next three to six months.

On May 21, 2018, we entered into the Option Agreement with SCM, whereby we granted an option to SCM to provide certain midstream services related to natural gas in Winkler and Loving Counties, Texas and Lea County, New Mexico subject to expiration and the terms of our existing gas agreement. The Option Agreement has a term commencing May 21, 2018 and terminating January 1, 2027, pursuant to its one-time option. We received $35.0 million from SCM as consideration for this option.

On January 31, 2018, we announced our entry into a new $50 million, six-year term loan with Riverstone Credit Partners, LLC, that refinanced our existing Bridge Loan. Approximately $31.8 million in proceeds were used to pay off and retire the First Lien Credit Agreement, and the remaining proceeds have been and will be used to fund our 2018 capital expenditures, acquisitions and other general corporate purposes, including payment of transaction expenses.

On January 30, 2018, we entered into a Securities Purchase Agreement with Värde to purchase from the Company 100,000 shares of a newly created Series C 9.75% Preferred Stock for an aggregate of $100 million in proceeds to the Company.

Information about our cash flows for the nine months ended September 30, 2018 and 2017 are presented in the following table (*amounts in thousands*):

| | Nine Months Ended September 30, | |
|---|---|---|
| | **2018** | **2017** |
| Cash provided by (used in): | | |
| Operating activities | $ 83,679 | $ (7,610) |
| Investing activities | (190,906) | (63,689) |
| Financing activities | 114,719 | 77,381 |
| Net change in cash, cash equivalents and restricted cash | $ 7,492 | $ 6,082 |

*Operating activities.* For the nine months ended September 30, 2018, net cash provided by operating activities was $83.7 million, compared to net cash $7.6 million used in the same period in 2017. The increase in cash provided by operating activities was primarily attributable to the proceeds of $35.0 million from SCM associated with the Option Agreement to provide future gas gathering midstream services, $10.0 million from SCM Water associated with an option to acquire our salt water disposal infrastructure, $5.0 million associated with a prefunded drilling bonus and approximately $33.7 million cash from operations during the nine months ended September 30, 2018.

*Investing activities*. For the nine months ended September 30, 2018, net cash used in investing activities was $190.9 million, compared to $63.7 million for the same period in 2017. The $190.9 million in cash used in investing activities during the nine months ended September 30, 2018 was primarily attributable to the following:

- approximately $116.8 million in drilling and completion costs;
- approximately $41.1 million cash consideration for the acquisition of leasehold acreage in the Delaware Basin in Lea County, New Mexico from OneEnergy Partners Operating, LLC;
- approximately $10.6 million cash consideration for the acquisition of proved and unproved oil and gas properties in Loving and Winkler Counties, Texas from VPD Texas, L.P.;

- approximately $7.1 million incurred on additional leasehold interests acquired from Anadarko, approximately $1.5 million of other leasehold interest and approximately $12.2 million on other lease bonuses primarily for leases in Winkler County, Texas and Lea County, New Mexico;
- approximately $0.7 million paid to Ameredev II, LLC and approximately $0.4 million paid to Felix Energy, LLC for leasehold exchange transactions; and
- approximately $0.5 million for fixed assets.

*Financing activities.* For the nine months ended September 30, 2018, net cash provided by financing activities was $114.7 million compared to cash provided by financing activities of $77.4 million during the same period in 2017. The $114.7 million in net cash provided by financing activities included the following:

- $97.5 million net proceeds from the issuance of 100,000 shares of Series C 9.75% Preferred Stock;
- $47.5 million net proceeds from the Riverstone First Lien Loans;
- $3.6 million proceeds from the exercise of stock warrants and stock options; and
- Offset by the payments of $31.8 million to retire the first lien bridge notes, $1.0 million for repurchase of the Company's common stock and $1.1 million for tax withholding for employee stock-based compensation awards.

*Off-Balance Sheet Arrangements*

We do not have any material off-balance sheet arrangements.

**Commitments and Contractual Obligations**

There have been no material changes in our contractual obligations during the three and nine months ended September 30, 2018.

**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

We are exposed to various market risks including, risks relating to changes in commodity prices, interest rate risk, customer credit risk and currency exchange rate risk as discussed below.

*Commodity Price Risk*

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Market risk refers to the risk of loss from adverse changes in oil and natural gas prices. Realized pricing is primarily driven by the prevailing domestic price for crude oil and spot prices applicable to the region in which we produce natural gas. Historically, prices received for oil and natural gas production have been volatile and unpredictable. We expect pricing volatility to continue. The prices that we receive depend on external factors beyond our control.

During the three months ended September 30, 2018, the overall production growth from market participants in our operating region led to stress on both infrastructure and transportation capacity, significantly impacting our realized commodity prices. The oil prices we received ranged from a low of $50.62 per barrel to a high of $57.24 per barrel. Natural gas prices during the same period ranged from a low of $1.59 per MCF to a high of $2.14 per MCF. NGL prices we received in the period ranged from a low of $0.48 per gallon to a high of $0.81 per gallon.

During the nine months ended September 30, 2018, the oil prices we received ranged from a low of $50.33 per barrel to a high of $63.53 per barrel. Natural gas prices during the same period ranged from a low of $1.43 per MCF to a high of $2.67 per MCF. NGL prices we received in the period ranged from a low of $0.48 per gallon to a high of $0.81 per gallon.

A significant decline in the prices of oil or natural gas could have a material adverse effect on our financial condition and results of operations. In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we may enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production.

The derivative contracts may include fixed-for-floating price swaps (whereby, on the settlement date, the Company will receive or pay an amount based on the difference between a pre-determined fixed price and a variable market price for a notional quantity of production), put options (whereby the Company pays a cash premium in order to establish a fixed floor price for a notional quantity of production and, on the settlement date, receives the excess, if any, of the fixed price floor over a variable market price), and costless collars (whereby, on the settlement date, the Company receives the excess, if any, of a variable market price over a fixed floor price up to a fixed ceiling price for a notional quantity of production). We do not enter into derivatives for trading or other speculative purposes. We believe that our use of derivatives and related hedging activities reduces our exposure to commodity price rate risk and does not expose us to material credit risk or any other material market risk.

The following Table summarizes our hedging arrangements as of September 30, 2018:

| Description | | Notional Volume (Bbls/d) | Production Period | Weighted Average Price ($/Bbl) |
|---|---|---|---|---|
| Oil Swaps | | 900 | October 2018 - December 2018 | $ 57.68 |
| Basis Swaps [1] | | 1,500 | October 2018 - December 2018 | $ (5.62) |
| Basis Swaps [1] | | 2,492 | January 2019 - December 2019 | $ (6.85) |
| Basis Swaps [1] | | 1,500 | January 2020 - December 2020 | $ (5.62) |
| 3 Way Collar | Floor sold price (put) | 1,252 | January 2019 - December 2019 | $ 45.00 |
| 3 Way Collar | Floor purchase price (put) | 1,252 | January 2019 - December 2019 | $ 55.00 |
| 3 Way Collar | Ceiling sold price (call) | 1,252 | January 2019 - December 2019 | $ 70.61 |
| Oil Collar | Floor purchase price (put) | 1,723 | October 2018 - December 2018 | $ 58.35 |
| Oil Collar | Ceiling sold price (call) | 1,723 | October 2018 - December 2018 | $ 70.02 |
| Oil Collar | Floor purchase price (put) | 1,000 | January 2019 - June 2019 | $ 52.50 |
| Oil Collar | Ceiling sold price (call) | 1,000 | January 2019 - June 2019 | $ 67.60 |

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

*Interest Rate Risk*

As of September 30, 2018, we have $50 million outstanding under our Amended and Restated Senior Secured Term Loan Credit Agreement with an applicable margin that varies from 5.75% to 6.75%. Our Second Lien Credit Agreement bears a fixed interest rate of 8.25% per annum, compounded quarterly in arrears and payable only in-kind by increasing the principal amount of the loan by the amount of the interest due on each interest payment date. In addition, holders of our shares of Series C Preferred Stock are entitled to receive cumulative preferential dividends, payable and compounded quarterly in arrears at an annual rate of 9.785% of the Stated Value until maturity.

Currently, we do not have any interest rate derivative contracts in place. If we incur significant debt with a risk of fluctuating interest rates in the future, we may enter into interest rate derivative contracts on a portion of our then outstanding debt to mitigate the risk of fluctuating interest rates.

*Customer Credit Risk*

Our principal exposure to credit risk is through receivables from the sale of our oil and natural gas production of approximately $11.5 million at September 30, 2018, and through actual and accrued receivables from our joint interest partners of approximately $3.0 million at September 30, 2018. We are subject to credit risk due to the concentration of our oil and natural gas receivables with our most significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the three months ended September 30, 2018, sales to three customers, Texican Crude & Hydrocarbons, LLC, Lucid Energy Delaware, LLC, and ETC Field Services LLC, accounted for approximately 80%, 17% and 2% of our revenue, respectively. For the nine months ended September 30, 2018, sales to these same three customers accounted for approximately 84%, 12% and 3% of our revenue, respectively. For the three months ended September 30, 2017, sales to two customers, Texican Crude & Hydrocarbons, LLC and ETC Field Services LLC, accounted for approximately 86% and 14% of our revenue, respectively. For the nine months ended September 30, 2017, sales to these same two customers accounted for approximately 83% and 15% of our revenue, respectively. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

*Currency Exchange Rate Risk*

We do not have any foreign sales and we accept payment for our commodity sales only in U.S. dollars. We are therefore not exposed to foreign currency exchange rate risk on these sales.

**Item 4. Controls and Procedures**

### *Evaluation of disclosure controls and procedures*

As required under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), at the end of the period we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(b), 13a-15(e) and 15d-15(e) under the Exchange Act). Our Chief Executive Officer and Chief Financial Officer have determined that disclosure controls and procedures were ineffective as of September 30, 2018 since the changes described below are still being evaluated.

### *Changes in internal control over financial reporting*

We regularly review our system of internal controls over financial reporting and make changes to our processes and systems to improve controls and increase efficiency. During the three months ended September 30, 2018, we took the following actions with respect to our full cost ceiling test calculation which constituted a material change in the Company's internal controls over financial reporting:

(i) implemented procedures to perform enhanced detailed reviews and analytical analysis on our tax position and projected tax position with respect to the impact of projected income taxes on the ceiling test; and

(ii) implemented procedures for additional reviews on the ceiling test calculation, including treatment of wells-in-process, future income tax effects, and future development cost and procedures to validate the ceiling test calculation with the reserve report.

Management is in the process of identifying additional procedures and process improvements to remediate the above identified material weakness and is continuing to validate the operating effectiveness of these controls over an appropriate period of time prior to concluding that the material weakness has been remediated.

## PART II – OTHER INFORMATION

**Item 1. Legal Proceedings.**

We may be the subject of threatened or pending legal actions and contingencies in the normal course of conducting our business. We provide for costs related to these matters when a loss is probable and the amount can be reasonably estimated. The effect of the outcome of these matters on our future results of operations and liquidity cannot be predicted because any such effect depends on future results of operations and the amount or timing of the resolution of such matters. For certain types of claims, we maintain insurance coverage for personal injury and property damage, product liability and other liability coverages in amounts and with deductibles that we believe are prudent, but there can be no assurance that these coverages will be applicable or adequate to cover adverse outcomes of claims or legal proceedings against us.

**Item 1A. Risk Factors.**

Risk factors relating to us are contained in Item 1A of our Annual Report. No material change to such risk factors has occurred during the three and nine months ended September 30, 2018.

**Item 2. Recent Sales of Unregistered Securities; Use of Proceeds from Registered Securities.**

**The following table sets forth information with respect to repurchases by the Company of its shares of common stock during the nine months ended September 30, 2018:**

| Period | Total number of shares purchased[(1)] | Average price 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 |
|---|---|---|---|---|
| January 1 - 31, 2018 | — | $ — | — | $ — |
| February 1 - 28, 2018 | — | $ — | — | $ — |
| March 1 - 31, 2018 | — | $ — | — | $ — |
| April 1- 30, 2018 (1) | 253,598 | $ 3.97 | — | $ — |
| May 1 - 31, 2018 | — | $ — | — | $ — |
| June 1 - 30, 2018 | — | $ — | — | $ — |
| July 1- 31, 2018 | — | $ — | — | $ — |
| August 1 - 31, 2018 | — | $ — | — | $ — |
| September 1 - 30, 2018 | — | $ — | — | $ — |
| Total | 253,598 | | — | |

(1) During the nine months ended September 30, 2018, equity securities were repurchased by an investment brokerage company, on behalf of the Company, as part of the Company's Share Repurchase Plan (the "Plan"). The Company entered into a share-repurchase agreement ("SRA") with an investment brokerage company to repurchase $1.0 million of the Company's common stock as part of the Plan. Under the terms of the SRA, the Company paid cash directly to the broker and received delivery of shares of the Company's common stock. All shares acquired by the Company under the SRA are accounted for at cost as treasury stock.

**Item 3. Defaults Upon Senior Securities**

None

**Item 4. Mine Safety Disclosures**

None

**Item 5. Other Information**

None

**Item 6. Exhibits**

**EXHIBIT INDEX**

| | |
|---|---|
| 3.1 | Amended and Restated Articles of Incorporation of Recovery Energy, Inc., dated as of October 10, 2011 (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on October 20, 2011). |
| 3.2 | Certificate of Amendment to the Articles of Incorporation of Recovery Energy, Inc., dated as of November 15, 2013 (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on November 19, 2013). |
| 3.3 | Certificate of Amendment to the Company's Articles of Incorporation (incorporated herein by reference to Annex A of the Company's Definitive Proxy Statement on Schedule 14A, filed on June 19, 2017). |
| 3.4 | Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on June 18, 2010). |
| 10.1 | Third Amendment to the Company's Omnibus Incentive Plan, dated June 28, 2018 (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on July 5, 2018). |
| 31.1* | Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). |
| 31.2* | Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). |
| 32.1* | Certification of the Chief Executive Officer pursuant to Rule 13a-14(b)/15d-14(b) of the Exchange Act, and 18 U.S.C. Section 1350. |
| 32.2* | Certification of the Chief Financial Officer pursuant to Rule 13a-14(b)/15d-14(b) of the Exchange Act, and 18 U.S.C. Section 1350. |
| 101.INS* | XBRL Instance Document |
| 101.SCH* | XBRL Taxonomy Extension Schema Document |
| 101.CAL* | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF* | XBRL Taxonomy Extension Definition Linkbase Document |
| 101.LAB* | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE* | XBRL Taxonomy Extension Presentation Linkbase Document |
| * | Filed herewith. |
| † | Indicates management contract or compensatory plan. |
| + | To be filed by amendment. |

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**Lilis Energy, Inc.**

| | |
|---|---|
| Date: November 1, 2018 By: | /s/ Ronald D. Ormand |
| | Ronald D. Ormand |
| | Chief Executive Officer |
| | (Principal Executive Officer) |
| Date: November 1, 2018 By: | /s/ Joseph C. Daches |
| | Joseph C. Daches |
| | President, Chief Financial Officer and Treasurer |
| | (Principal Financial and Accounting Officer) |

**EXHIBIT 31.1**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**
**PURSUANT TO RULE 13A-14(A) OF**
**THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Ronald D. Ormand, certify that:

1. I have reviewed this report on Form 10-Q of Lilis Energy, Inc. ("Registrant");

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 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;

   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;

   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; and

5. The Registrant's other certifying officer 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 weaknesses 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.

/s/ Ronald D. Ormand

Ronald D. Ormand
*Executive Chairman of the Board and Chief Executive Officer*

November 1, 2018

**EXHIBIT 31.2**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**
**PURSUANT TO RULE 13A-14(A) OF**
**THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Joseph C. Daches, certify that:

1. I have reviewed this report on Form 10-Q of Lilis Energy, Inc. ("Registrant");

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 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;

    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;

    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; and

5. The Registrant's other certifying officer 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 weaknesses 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.

/s/ Joseph C. Daches

Joseph C. Daches
*President, Chief Financial Officer and Treasurer*

November 1, 2018

**EXHIBIT 32.1**

**CERTIFICATION PURSUANT TO**
**18 U.S.C. SECTION 1350,**
**AS ADOPTED PURSUANT TO**
**RULE 13A-14(B)/15D-14(B) OF**
**THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

In connection with the Quarterly Report of Lilis Energy, Inc. (the "Company") on Form 10-Q for the period ended September 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(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.

/s/ Ronald D. Ormand

Ronald D. Ormand
*Executive Chairman of the Board and Chief Executive Officer*

November 1, 2018

**EXHIBIT 32.2**

**CERTIFICATION PURSUANT TO**
**18 U.S.C. SECTION 1350,**
**AS ADOPTED PURSUANT TO**
**RULE 13A-14(B)/15D-14(B) OF**
**THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

In connection with the Quarterly Report of Lilis Energy, Inc. (the "Company") on Form 10-Q for the period ended September 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(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.

/s/ Joseph C. Daches

Joseph C. Daches
*President, Chief Financial Officer and Treasurer*

November 1, 2018