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 June 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 August 7, 2018, 64,247,893 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 on Form 10-K for the year ended December 31, 2017. 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.

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)

	June 30, 2018	December 31, 2017
	(Unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 27,398	$ 17,462
Accounts receivables, net of allowance of $25 and $39, respectively	17,961	7,426
Derivative instruments	1,775	—
Prepaid expenses and other current assets	867	584
Total current assets	48,001	25,472
Oil and natural gas properties, full cost method of accounting		
Unproved	168,359	101,771
Proved	251,928	141,717
Total oil and natural gas properties	420,287	243,488
Less: accumulated depreciation, depletion, amortization and impairment	(83,505)	(73,183)
Total oil and natural gas properties, net	336,782	170,305
Other assets	540	167
Total assets	$ 385,323	$ 195,944
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities:		
Accounts payable	$ 14,284	$ 10,488
Accrued liabilities	14,088	7,634
Revenue payable	14,239	6,460
Dividends payable	4,117	—
Derivative instruments	2,987	853
Total current liabilities	49,715	25,435
Asset retirement obligations	1,099	726
Long-term debt, less current maturities	158,548	127,794
Derivative instruments	66,710	72,937
Long-term deferred revenue	34,650	—
Total liabilities	310,722	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 June 30, 2018	97,506	—
Stockholders’ deficit:		
Common stock, $0.0001 par value per share; 150,000,000 shares authorized, 64,045,923 and 53,368,331 shares issued and outstanding as of June 30, 2018 and December 31, 2017, respectively, of which 253,598 shares are being held as treasury stock as of June 30, 2018	6	5
Additional paid-in capital	300,336	272,335
Accumulated deficit	(322,250)	(303,288)
Treasury stock (253,598 shares at cost)	(997)	—
Total stockholders’ deficit	(22,905)	(30,948)
Total liabilities and stockholders’ deficit	$ 385,323	$ 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 June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Revenues:				
Oil sales	$ 14,254	$ 4,167	$ 26,843	$ 6,662
Natural gas sales	1,144	538	2,034	1,039
Natural gas liquid sales	2,085	600	3,001	686
Total revenues	17,483	5,305	31,878	8,387
Operating expenses:				
Production costs	2,670	1,097	5,760	1,927
Gathering, processing and transportation	872	338	1,334	437
Production taxes	1,135	278	2,158	420
General and administrative	7,380	16,169	17,844	25,329
Depreciation, depletion, amortization and accretion	5,759	1,358	10,400	2,504
Total operating expenses	17,816	19,240	37,496	30,617
Operating loss	(333)	(13,935)	(5,618)	(22,230)
Other income (expense):				
Other income (expense)	—	(141)	1	(133)
Loss from commodity derivatives	(2,802)	—	(4,572)	—
Fair value change in other derivative liabilities	(19,501)	(2,418)	8,887	(2,114)
Interest expense	(8,572)	(6,654)	(17,660)	(7,427)
Total other expense	(30,875)	(9,213)	(13,344)	(9,674)
Net loss before income taxes	(31,208)	(23,148)	(18,962)	(31,904)
Income tax expense	—	—	—	—
Net loss	(31,208)	(23,148)	(18,962)	(31,904)
Less:				
Dividends on redeemable 6% preferred stock	—	(92)	—	(122)
Dividends and deemed dividends on Series B convertible preferred stock	—	(4,422)	—	(4,635)
Dividends on Series C convertible preferred stock	(2,465)	—	(4,117)	—
Net loss attributable to common stockholders	$ (33,673)	$ (27,662)	$ (23,079)	$ (36,661)
Net loss per common share - basic and diluted	$ (0.53)	$ (0.62)	$ (0.40)	$ (1.07)
Weighted average common shares outstanding - basic and diluted	64,098,309	44,332,270	57,801,098	34,282,784

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 Paid In Capital	Treasury Stock		Accumulated Deficit	Total
	Shares	Amount		Shares	Amount		
Balance, December 31, 2017	53,368,331	$ 5	$ 272,335	—	$ —	$ (303,288)	$ (30,948)
Stock based compensation	—	—	5,554	—	—	—	5,554
Common stock issued for restricted stock	467,860	—	—	—	—	—	—
Common stock forfeited for taxes withheld on stock awards	(134,235)	—	(509)	—	—	—	(509)
Common stock for acquisition of oil and gas properties	6,940,722	1	24,777	—	—	—	24,778
Exercise of warrants	2,848,440	—	1,051	—	—	—	1,051
Exercise of stock options	554,805	—	1,022	—	—	—	1,022
Reclassification of warrant derivative liabilities	—	—	223	—	—	—	223
Purchase of treasury stock	—	—	—	(253,598)	(997)	—	(997)
Dividends on Series C convertible preferred stock	—	—	(4,117)	—	—	—	(4,117)
Net loss	—	—	—	—	—	(18,962)	(18,962)
Balance, June 30, 2018	64,045,923	$ 6	$ 300,336	(253,598)	$ (997)	$ (322,250)	$ (22,905)

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)

	Six Months Ended June 30,	
	2018	**2017**
Cash flows from operating activities:		
Net loss	$ (18,962)	$ (31,904)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Stock based compensation	5,554	9,386
Bad debt expense	(14)	—
Amortization of debt issuance cost and debt discount	8,685	5,210
Payable in-kind interest	6,437	1,341
Loss from commodity derivatives, net	4,572	2,072
Net cash settlement paid for commodity derivative contracts	(1,710)	—
Gain in fair value of debt conversion and warrant derivatives	(8,887)	1
Loss in fair value of conditionally redeemable 6% preferred stock	—	41
Depreciation, depletion, amortization and accretion of asset retirement obligation	10,400	2,504
Proceeds for options to provide future gas midstream services, net of transaction costs	34,650	—
Changes in operating assets and liabilities:		
Accounts receivable	(10,521)	(1,756)
Prepaid expenses and other assets	(436)	(479)
Accounts payable and accrued liabilities	12,442	6,170
Net cash provided by (used in) operating activities	42,210	(7,414)
Cash flows from investing activities:		
Net proceeds from sale of DJ Basin properties	—	1,082
Acquisition of oil and natural gas properties	(69,820)	—
Capital expenditures	(76,160)	(40,925)
Net cash used in investing activities	(145,980)	(39,843)
Cash flows from financing activities:		
Proceeds from issuance of Series C Preferred Stock	100,000	—
Proceeds from private placement	—	20,000
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 and equity issuance costs	(5,040)	(1,600)
Repayment of debt	(31,821)	(40,385)
Repurchase of common stock	(997)	—
Proceeds from exercise of warrants and stock options	2,073	392
Payment for tax withholding on stock-based compensation	(509)	(1,555)
Net cash provided by financing activities	113,706	78,258
Net increase in cash, cash equivalents and restricted cash	9,936	31,001
Cash, cash equivalents and restricted cash at beginning of period	17,462	11,738
Cash, cash equivalents and restricted cash at end of period	$ 27,398	$ 42,739
Supplemental disclosure:		
Cash paid for interest	$ 2,538	$ 1,318

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

Lilis Energy, Inc. and Subsidiaries
Notes to Condensed Consolidated Financial Statements
(Unaudited)

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 which includes 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 accounting principles generally accepted 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 on March 9, 2018, (the "2017 Annual Report on Form 10-K").

Use of Estimates

The accompanying condensed consolidated financial statements are prepared in conformity with generally accepted accounting principles in the United States ("U.S. 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. The following reclassifications have been made to the three and six months ended June 30, 2017: (i) the income from operator's overhead recovery of approximately $0.12 million and $0.27 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; and (ii) $0.6 million of the escrow on a drilling rig has been reclassified from investing activities to cash, cash equivalents and restricted cash in the condensed consolidated statement of cash flows as required with the adoption of ASU No. 2016–18, "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force), see Recently Adopted Accounting Standards.

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 revenues from customers are derived from production and sales of crude oil, natural gas and natural gas liquids 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 and 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:

For the three months ended June 30, 2018	**As Reported**	**Balances without Adoption of ASC 606**	**Increase (Decrease)**
Condensed Consolidated Statements of Operations:			
Revenues	$ 17,483	$ 17,498	$ (15)
Operating expenses	$ (872)	$ (887)	$ (15)
For the six months ended June 30, 2018			
Condensed Consolidated Statements of Operations:			
Revenues	$ 31,878	$ 31,943	$ (65)
Operating expenses	$ (1,334)	$ (1,399)	$ (65)
As of June 30, 2018			
Condensed Consolidated Balance Sheets:			
Accounts receivable	$ 8,378	$ 8,443	$ (65)
Accrued liabilities	$ (394)	$ (459)	$ (65)

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 $15,000 and $65,000 from both revenues and operating expenses during the three and six months ended June 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 outstanding as of January 1, 2018 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. The standard 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, we 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 our accompanying condensed consolidated statement of cash flows for the six months ended June 30, 2017, from what was previously presented in our Quarterly Report on Form 10–Q for the quarterly period ended June 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 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 guidance requires adoption by application of a modified retrospective transition approach for existing long-term leases and is effective for fiscal years beginning after December 15, 2018, including interim periods within those years. Oil and natural gas leases are scoped out of ASU 2016-02. The Company is currently gathering all lease and other agreements which may contain embedded leases to evaluate the impact that ASU 2016-02 would have on the Company's consolidated financial statements. The Company expects that the adoption of ASU 2016-02 will likely increase the Company's recorded assets and liabilities. As of June 30, 2018, the Company is continuing to evaluate each of its lease arrangements and has not yet determined the aggregate impact on its consolidated financial statements.

Accrued Liabilities

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

	June 30, 2018	December 31, 2017
	($ in thousands)	
Accrued bonus	$ 1,234	$ 3,000
Accrued capital expenditures	9,474	3,615
Other accrued liabilities	3,380	1,019
	$ 14,088	$ 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 the 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 be entitled 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 NGL produced on 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 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 June 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 NGL 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 ourselves principals in these arrangements.

Practical expedients

A significant number of the Company's product sales are short-term in nature with contract term 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 June 30, 2018	**Short-term contracts**	**Long-term contracts**	**Total**
Crude Oil	$ 14,254	$ —	$ 14,254
Natural Gas	$ 145	$ 999	$ 1,144
NGLs	$ 265	$ 1,820	$ 2,085

Six Months Ended June 30, 2018	**Short-term contracts**	**Long-term contracts**	**Total**
Crude oil	$ 26,843	$ —	$ 26,843
Natural gas	$ 524	$ 1,510	2,034
NGLs	$ 774	$ 2,227	$ 3,001

Customer Credit Risk

Our principal exposures to credit risk is through receivables from the sale of our oil and natural gas production of approximately $8.4 million at June 30, 2018, and through receivables from our joint interest partners of approximately $5.0 million together with $4.2 million of accrued unbilled receivables at June 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 June 30, 2018, sales to three customers, Texican Crude & Hydrocarbons, LLC, Lucid Energy Delaware, LLC, and ETC Field Services LLC, accounted for approximately 86%, 12% and 2% of our revenue, respectively. For the six months ended June 30, 2018, sales to these same three customers accounted for approximately 86%, 10% and 4% of our revenue, respectively. For the three months ended June 30, 2017, sales to two customers, Texican Crude & Hydrocarbons, LLC and ETC Field Services LLC, accounted for approximately 79% and 21% of our revenue, respectively. For the six months ended June 30, 2017, sales to these same two customers accounted for approximately 78% and 22% 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.

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/or plugging and abandoning non-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, (b) estimated future development cost to be incurred in developing proved reserves; and (c) estimated decommissioning and abandonment/restoration costs, net of estimated salvage values, 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 and 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 June 30, 2018, the ceiling value of the Company's reserves was calculated based upon SEC pricing of $57.67 per barrel for oil, $2.92 per MMBtu for natural gas and $54.79 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 depletions.

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

	June 30, 2018		December 31, 2017	
	(In thousands)			
Unproved unevaluated acreage:				
Beginning balance		101,771	$	24,461
Lease purchases		86,181		78,110
Transfer and other reclassification to proved properties		(19,593)		(800)
Total unproved acreage	$	168,359	$	101,771
Wells in progress:				
Beginning balance	$	—	$	7,453
Additions		625		—
Reclassification to evaluated properties		—		(7,453)
Total wells in progress not subject to DD&A	$	625	$	—

During the six months ended June 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 six months ended June 30, 2017, no impairment was recorded on the Company's unproved oil and natural gas properties.

For the three months ended June 30, 2018 and 2017, depreciation, depletion, amortization and accretion expense related to proved properties was $5.8 million and $1.4 million , respectively. For the six months ended June 30, 2018 and 2017, depreciation, depletion, amortization and accretion expense related to proved properties was $10.4 million and $2.5 million, respectively.

NOTE 5 – ACQUISITIONS AND DIVESTITURES

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 consists 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 plus $0.5 million of related acquisition costs (the "VPD Acquisition"). The 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 Term Loan 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 (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.

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 a 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 which was the total cash consideration.

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 recorded at fair value which was the total cash consideration of approximately $49.7 million.

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 June 30, 2018				
Oil and natural gas derivative swap contracts	$ —	$ (2,106)	$ —	$ (2,106)
Oil and natural gas derivative collar contracts	—	(2,899)	—	(2,899)
Oil and natural gas derivative basis swap contracts	—	910	—	910
Second Lien Term Loan conversion features	—	—	(63,827)	(63,827)
Total	$ —	$ (4,095)	$ (63,827)	$ (67,922)
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 Term Loan 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 Partners, Inc., 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 Loan repaid, prepaid or accelerated. The number of shares 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 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 Loan require the conversion features to be recorded as embedded derivatives and bifurcated from its host contracts, the Loan, and accounted for separately from the debt. The conversion features contained in the 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 Loan under the Second Lien Credit Agreement. Change in fair value is accounted for in the condensed consolidated statement operations. As of December 31, 2017, the fair value of the embedded derivative under the Second Lien Credit Agreement associated with the Loan conversion features was a liability of approximately $72.7 million. As of June 30, 2018, the fair value of the embedded derivative liability was $63.8 million. As a result, the Company recorded an unrealized loss of $19.5 million and an unrealized gain of $8.9 million on the change in fair value of derivative liabilities associated with the Loan conversion features for the three and six months ended June 30, 2018, respectively.

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 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 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 six months ended June 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 asset retirement obligations for the six months ended June 30, 2018 and year ended December 31, 2017:

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
	(In thousands)	
ARO, beginning of period	$ 952	$ 1,257
Additional liabilities incurred	315	20
Accretion expense	48	82
Liabilities settled	(87)	(288)
Revision in estimates	(66)	(119)
	1,162	952
Less: current portion of ARO	(63)	(226)
ARO, end of period	$ 1,099	$ 726

NOTE 8 - DERIVATIVES

Embedded Derivatives

As discussed in Note 6, the Second Lien Term 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 Term 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 Term 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 June 30, 2018 and December 31, 2017, the fair value of the derivative liability was $63.8 million and $72.7 million, respectively. As a result, the Company recognized an unrealized loss of $19.5 million and unrealized gain of $8.9 million in its condensed consolidated statement of operations for the three and six months ended June 30, 2018, respectively. There were no derivative liabilities associated with convertible debt instruments for the three and six months ended June 30, 2017.

Commodity Derivatives

To reduce the impact of fluctuations in oil and natural gas prices on the Company's revenues, or 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 June 30, 2018:

Description		**Notional Volume (Bbls/d)**	**Production Period**	**Weighted Average Price ($/Bbl)**
Oil Swaps		900	July 2018 - December 2018	$ 57.68
Basis Swaps		1,500	July 2018 - December 2018	$ (5.62)
Basis Swaps		1,500	January 2019 - December 2019	$ (5.62)
Basis Swaps		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)	1,763	July 2018 - December 2018	$ 58.35
Oil Collar	Ceiling sold price (call)	1,763	July 2018 - December 2018	$69.86
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

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
	(in thousands)	
Beginning fair value of commodity derivatives	$ (853)	$ —
Change in fair value of derivative instruments	(4,572)	(1,063)
Net settlements paid on crude oil derivative contracts	1,710	96
Change in settlements accrued on crude oil derivative contracts	(383)	114
Ending fair value of commodity derivatives, net	$ (4,098)	$ (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 June 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	$ 3,249	$ (1,474)	$ 1,775
Long-term asset	—	—	—
Total asset	$ 3,249	$ (1,474)	$ 1,775
Offsetting Derivative Liabilities:			
Current liability	$ 4,444	$ (1,457)	$ 2,987
Long-term liability	2,738	148	2,886
Total liability	$ 7,182	$ (1,309)	$ 5,873

	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

	June 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	$ 47,805	$ —
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	110,743	96,431
6% note payable to SOS Investment, LLC, due 2019	—	1,000
Other notes payable, due 2018	5	11
Total long-term debt	$ 158,553	$ 127,805
Less: current portion	(5)	(11)
Total long-term debt, net of current portion	$ 158,548	$ 127,794

As of June 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
June 30, 2018:				
Riverstone First Lien Loans, due January 2021	$ 50,000	$ —	$ (2,195)	$ 47,805
Second Lien Term Loans, due April 2021	150,000	12,189	(51,446)	110,743
Total:	$ 200,000	$ 12,189	$ (53,641)	$ 158,548
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 Term 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 Term Loan, the “Second Lien Loans”) 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 of the availability 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.

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 Värde Partners, Inc., as 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 Lender’s 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 provides 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 June 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 Term Loan. The debt discount is amortized over the term of the Second Lien Loans using effective interest rate.

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.

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 $10,000,000 (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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Interest on term loans	$ 1,078	$ 330	$ 2,538	$ 847
Interest on notes payable	—	15	—	29
Paid-in-kind interest on term loans	3,269	1,341	6,437	1,341
Amortization of debt financing costs	262	1,495	881	1,622
Amortization of discount on term loans	3,963	3,473	7,804	3,588
Total	$ 8,572	$ 6,654	$ 17,660	$ 7,427

NOTE 10 - LONG-TERM DEFERRED REVENUE

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 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 million which was recorded as deferred revenue in long-term deferred revenue.

NOTE 11 - RELATED PARTY TRANSACTIONS

There were no related party transactions during the three months ended June 30, 2018 and 2017. During the six months ended June 30, 2018 and 2017, the Company was engaged in the following transactions, which occurred during the first quarters of 2018 and 2017, with certain related parties:

Related Party	Transactions	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
		($ in thousands)	
Directors and Officers:			
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	$ 10,611	$ —
		$ 10,611	$ —

(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 11 – *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 Partners, Inc. (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 $100,000,000. Värde Partners, Inc. is the lead lender, and certain private funds affiliated with Värde Partners, Inc. 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.

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 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. The Company expects to pay dividends-in-kind for the foreseeable future. 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 June 30, 2018, the Company had $4.1 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 of 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 six months ended June 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 warrant activity for the six months ended June 30, 2018:

	Warrants	Weighted-Average Exercise Price
Outstanding at January 1, 2018	11,882,800	$ 3.46
Exercised	(2,848,440)	$ 2.50
Expired or canceled	(2,324,304)	$ 3.84
Outstanding at June 30, 2018	6,710,056	$ 3.27

NOTE 13 - SHARE BASED AND OTHER COMPENSATION

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

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
	Stock Options	Restricted Stock	Total	Stock Options	Restricted Stock	Total
Share-based compensation expensed	$ 1,238	$ 4,316	$ 5,554	$ 3,273	$ 6,113	$ 9,386
Unrecognized share-based compensation costs	$ 1,346	$ 4,777	$ 6,123	$ 7,669	$ 2,094	$ 9,763
Weighted average amortization period remaining (in years)	0.56	0.63	1.19	0.82	0.74	1.56

Restricted Stock

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

	Number of Shares	Weighted Average Grant Date Price
Outstanding at January 1, 2018	2,475,266	$ 4.22
Granted	799,944	$ 4.28
Vested and issued	(654,946)	$ (4.06)
Forfeited or canceled [(1)]	(847,898)	$ (4.88)
Outstanding at June 30, 2018	1,772,366	$ 3.93

Restricted Stock Units

A summary of restricted stock unit grant activity pursuant to the 2012 Plan for the six months ended June 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 June 30, 2018	—	$ —

Stock Options

A summary of stock option activity pursuant to the 2016 Plan for the six months ended June 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	$	3.82		
Exercised	(675,500)	$	(1.66)		
Forfeited or canceled (1)	(1,480,850)	$	(4.20)		
Outstanding at June 30, 2018	5,501,150	$	3.68	4,201,200	8.4

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

During the six months ended June 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 $3.68. During the six months ended June 30, 2018, the Company received $1.0 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 six months ended June 30, 2018 and 2017 *(in thousands)*:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net loss	$ (31,208)	(23,148)	$ (18,962)	$ (31,904)
Less: dividends on redeemable preferred stock	—	(92)	—	(122)
Less: dividends and deemed dividends on Series B convertible preferred stock	—	(4,422)	—	(4,635)
Less: dividends on Series C convertible preferred stock	(2,465)	—	(4,117)	—
Net loss attributable to common stockholders	$ (33,673)	$ (27,662)	$ (23,079)	$ (36,661)
Weighted average common shares outstanding - basic and diluted	64,098,309	44,332,270	57,801,098	34,282,784
Net loss per common share – basic and diluted	$ (0.53)	$ (0.62)	$ (0.40)	$ (1.07)

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

	2018	2017
Stock Options	5,501,150	7,158,500
Restricted Stock Units	—	9,999
Series C Preferred Stock	20,312,607	—
Stock Purchase Warrants	6,710,056	12,523,045
Conversion of Term Loans	23,970,219	13,572,950
	56,494,032	33,264,494

NOTE 15 - SUPPLEMENTAL NON-CASH TRANSACTIONS

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

	Six Months Ended June 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	—	14,087
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	—	371
Change in capital expenditures for drilling costs in accrued liabilities	5,859	871
Accrued dividends for Series C Preferred Stock	4,117	—
Change in asset retirement obligations	66	—
Issuance of common stock for drilling services	—	96
Increase in final settlement on the divestiture of DJ Basin properties in accrued liabilities	—	584
Deemed dividends on Series B 6% Convertible Preferred Stock associated with beneficial conversion features	—	3,767
Fair value of derivative liabilities associated with conversion features of Second Lien Term Loan	—	36,741

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

Environmental and Governmental Regulation

As of June 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 June 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

Firm Oil Takeaway and Pricing Agreement

On August 2, 2018, the Company successfully executed a five-year agreement with an affiliate of Salt Creek Midstream, LLC (“SCM”), an ARM Energy Holdings' affiliate, to secure firm takeaway and pricing. Commencing in the second half of 2019, the agreement locks down firm long-haul pipeline capacity to the Gulf Coast as well as Gulf Coast pricing.

Under the terms of the agreement, 6,000 Bbl/d of firm capacity will be delivered to Gulf Coast for one year-beginning on July 1, 2019. During the next four years, from July 1, 2020 through June 30, 2024, firm capacity will adjust to 5,000 Bbl/d. All volumes have with firm Gulf Coast pricing throughout the 5-year term. The Company also has the ability to expand its capacity with SCM during the term of the agreement as the Company believes having flexibility with barrels in the future is desirable.

Water Gathering and Disposal Agreement

In July 2018, the Company entered into a water gathering and disposal agreement with SCM Water, LLC ("SCM Water"), an ARM Energy Holdings' affiliate. 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 expenditure 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). The Company has sold to SCM Water for cash consideration upon closing, with additional payments based on reaching certain milestones, an option to acquire the Company’s existing water infrastructure, a system which is comprised of approximately 14 miles of pipeline and one SWD. The Company is actively working on permitting additional SWD locations. 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 payment of $10.0 million for option to acquire our existing water infrastructure for the firm transportation and pricing for crude oil and a $5.0 million for prefunded drilling bonus. The Company expects to receive the remaining $5.0 million for both the right-of-way/easement bonus and hitting target of 40,000 barrels per day of produced water during the third quarter of 2018.

Exchange of Acreage

The Company entered into a definitive acre-for-acre trade agreement of approximately 750 net acres in Lea County, New Mexico on August 1, 2018. The transaction increases the Company's Gross Working Interest (GWI) in its Delaware Basin acreage in New Mexico up to 100% in core areas of the Company's operations. All the acreage that was traded away was in non-operated sections with lower working interests. The transaction is subject to customary adjustments and is expected to close August 20, 2018.

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 on Form 10-K for the year ended December 31, 2017, 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 on Form 10-K for the year ended December 31, 2017.

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.

Significant second quarter 2018 highlights include:

- Our second quarter shows a significant increase in revenue from oil and natural gas operations from $5.3 million during the three months ended June 30, 2017 to $17.5 million during the three months ended June 30, 2018. The increase of $12.2 million or 181% was primarily attributable to sales volume increase to 437,257 barrels of oil equivalent ("BOE") from 155,367 BOE for the same period in 2017, as well as an increase in realized oil and natural gas prices.

- As of June 30, 2018, our estimated daily production capacity rate was 6,690 Boepd. Since then our current daily production rates has exceeded 7,300 BOE per day ("Boepd"). We have increased the 2018 target exit rate to 8,000 Boepd as a result of increasing production from successful development program and longer lateral development.

- We placed several production hedges on approximately 2,000 average Boepd that yield an average floor of $52.71 and a ceiling of $69.36 for the remainder of 2018 and we have also placed several basis hedges on 1,500 Midland-Cushing Boepd with an average cost differential of $5.62 for 2018.

- We increased our liquidity by approximately $55 million without dilution through the following infrastructure transactions with Salt Creek Midstream LLC ("SCM"):

    - crude oil gathering agreement and option agreement in order to support the Company's strategic efforts to secure long-term infrastructure solutions and future movement of its oil production out of the Delaware Basin, as well as maximize crude pricing. We received an upfront fee of $35.0 million for option to provide gas gathering midstream services in the future;

    - water gathering and disposal agreement for SCM to build out new gathering and disposal infrastructure to all of our current and future well locations. Total 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 option to acquire our existing water infrastructure for the firm transportation and pricing for crude oil and a $5.0 million for prefunded drilling bonus. The Company expects to receive the remaining $5.0 million for both the right-of-way/easement bonus and hitting target of 40,000 barrels per day of produced water during the third quarter of 2018; and

    - executed a five-year agreement to secure firm takeaway and sales agreement to secure firm takeaway pipeline capacity and pricing on a long-haul pipeline capacity to the Gulf Coast commencing July 1, 2019. We also intend on obtaining Gulf Coast pricing with SCM during the first quarter of 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 Salt Creek. 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.

- We have drilled and completed operated horizontal wells in the Wolfcamp A, B and XY and 3rd Bone Spring wells in the Delaware Basin. Continuing the strategy of delineating and de-risking the acreage position both geographically and geologically.

- The drilling program for the second half of 2018 is targeting, almost exclusively, 1.5-mile laterals to facilitate cost efficiencies in production.

Drilling Program

We have a drilling program for 2018 to drill up to 17 gross (11.9 net) wells. Our drilling program is contingent upon our access to sufficient capital to fully execute our plans.

Results of Operations – For the Three and Six Months Ended June 30, 2018 and 2017

During the six months ended June 30, 2018, we drilled or were in the process of drilling 11 gross (9.4 net) horizontal wells and completed or were in the process of completing 12 gross (10.5 net) horizontal wells. As of June 30, 2018, we have production flowing from our 19 horizontal wells and 12 legacy vertical wells with an estimated productive capacity of approximately 6,690 net BOE per day.

Since the three months ended June 30, 2017, we have placed 13 gross (10.6 net) wells into production, contributing to most of the net sales volume increase of 281,890 BOE for the three months ended June 30, 2018 and the net sales volume increase of 510,274 BOE for the six months ended June 30, 2018.

Oil, natural gas and NGL sales

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

	Three Months Ended June 30,			
	2018	**2017**	**Variance**	**%**
Net production:				
Oil (Bbls)	238,772	94,048	144,724	154 %
Natural gas (Mcf)	746,612	185,953	560,659	302 %
NGL (Bbl)	74,050	30,327	43,723	144 %
Total (BOE)	437,257	155,367	281,890	181 %
Average daily production (BOE/d)	4,805	1,707	3,098	181 %
Average realized sales price:				
Oil (Bbl)	$ 59.70	$ 44.31	$ 15.39	35 %
Natural gas (Mcf)	$ 1.53	$ 2.89	$ (1.35)	(47)%
NGL (Bbl)	$ 28.16	$ 19.83	$ 8.32	42 %
Total (BOE)	$ 39.98	$ 34.14	$ 5.84	17 %
Oil, natural gas and NGL revenues *(in thousands):*				
Oil revenue	$ 14,254	$ 4,167	10,087	242 %
Natural gas revenue	1,144	538	606	113 %
NGL revenue	2,085	600	1,485	248 %
Total revenue	$ 17,483	$ 5,305	$ 12,178	230 %

Oil, natural gas and NGL sales. For the three months ended June 30, 2018, oil, natural gas and NGL sales revenue increased $12.2 million to $17.5 million, compared to $5.3 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 June 30, 2018, compared to the same period in 2017. Total sales volume increased by 281,890 BOE to 437,257 BOE during the three months ended June 30, 2018, from 155,367 BOE during the same period in 2017. Higher realized oil and NGL prices of $59.70 and $28.16 per Bbl, respectively, also contributed to the increased revenues for the quarter. For the three months ended June 30, 2018, compared to the same period in 2017, total revenue increased by $2.6 million and $9.6 million as a result of the increase in sales volumes and in average realized price per BOE, respectively. The decrease in the average realized natural gas price by $1.35 per Mcf during the three months ended June 30, 2018 was attributable to a combination of factors, including lower spot pricing in the natural gas market, higher H2S levels affecting natural gas quality, different marketing terms stemming from our transition to a new primary natural gas purchaser in 2018, and a higher NGL yield from natural gas processing that resulted in a lower Btu yield for each MCF of natural gas.

The following sets forth selected revenue and sales volume data for the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30,			
	2018	2017	Variance	%
Net production:				
Oil (Bbls)	447,211	145,391	301,820	208 %
Natural gas (Mcf)	1,160,644	353,982	806,662	228 %
NGL (Bbl)	108,487	34,477	74,010	215 %
Total (BOE)	749,139	238,865	510,274	214 %
Average daily production (BOE/d)	4,139	1,320	2,819	214 %
Average realized sales price:				
Oil (Bbl)	$ 60.02	45.82	$ 14.20	31 %
Natural gas (Mcf)	$ 1.75	2.94	$ (1.18)	(40)%
NGL (Bbl)	$ 27.66	19.90	$ 7.76	39 %
Total (BOE)	$ 42.55	35.12	$ 7.43	21 %
Oil, natural gas and NGL revenues *(in thousands):*				
Oil revenue	$ 26,843	6,662	$ 20,181	303 %
Natural gas revenue	2,034	1,039	995	96 %
NGL revenue	3,001	686	2,315	337 %
Total revenue	$ 31,878	$ 8,387	$ 23,491	280 %

Oil, natural gas and NGL sales. For the six months ended June 30, 2018, oil, natural gas and NGL sales revenue increased by $23.5 million to $31.9 million, compared to $8.4 million for the same period during 2017. The increase of $23.5 million was due primarily to higher oil, natural gas and NGL sales volumes in the six months ended June 30, 2018 compared to the same period in 2017. Total sales volume increased by 510,274 BOE to 749,139 BOE during the six months ended June 30, 2018 from 238,865 BOE during the same period in 2017. Higher realized oil and NGL prices of $60.02 and $27.66 per Bbl, respectively, also contributed to the increased revenues for the six months ended June 30, 2018. For the six months ended June 30, 2018, total revenue increased by $17.9 million and $5.6 million as a result of the increase in sales volumes and in average realized price per BOE, respectively. The decrease in the average realized natural gas price by $1.18 per Mcf during the six months ended June 30, 2018 was attributable to a combination of factors, including lower spot pricing in the natural gas market, higher H2S levels affecting natural gas quality, different marketing terms stemming from our transition to a new primary natural gas purchaser in 2018, and a higher NGL yield from natural gas processing that resulted in a lower Btu yield for each MCF of natural gas.

Operating Expenses

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

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Variance	%
Operating Expenses per BOE:				
Production costs	$ 6.11	7.06	$ (0.95)	(13)%
Gathering, processing and transportation	1.99	2.18	(0.18)	(8)%
Production taxes	2.60	1.79	$ 0.81	45 %
General and administrative	16.88	104.07	$ (87.19)	(84)%
Depreciation, depletion, amortization and accretion	13.17	8.74	$ 4.43	51 %
Total operating expenses per BOE	$ 40.75	$ 123.84	$ (83.09)	(67)%

	2018	2017	Variance	%
Operating Expenses:				
Production costs	$ 2,670	$ 1,097	$ 1,573	143 %
Gathering, processing and transportation	872	338	534	158 %
Production taxes	1,135	278	857	308 %
General and administrative	7,380	16,169	(8,789)	(54)%
Depreciation, depletion, amortization and accretion	5,759	1,358	4,401	324 %
Total Operating Expenses	$ 17,816	$ 19,240	$ (1,424)	(7)%

Production costs. Our production costs increased from $1.1 million, or $7.06 per BOE, for the three months ended June 30, 2017, to $2.7 million, or $6.11, per BOE for the three months ended June 30, 2018. The significant increase in production costs was primarily due to the increased production volumes during the three months ended June 30, 2018. However, the decrease of $0.95 per BOE in production costs resulted from lower workover and overhead costs per BOE produced.

Gathering, processing and transportation. Our gathering, processing and transportation costs increased by $0.5 million to $0.8 million for the three months ended June 30, 2018 compared to $0.3 million during the same period in 2017. The increase resulted from the impact of higher sales volumes and rate-related increases.

Production taxes. Production taxes were $1.1 million for the three months ended June 30, 2018, compared to $0.3 million for the same period in 2017, an increase of $0.9 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 significant increase in production taxes corresponds to the increase in production revenues during the three months ended June 30, 2018.

Depreciation, depletion, amortization and accretion. Our depreciation, depletion and amortization expense increased by $4.4 million to $5.8 million for the three months ended June 30, 2018, compared to $1.4 million during the same period in 2017. The increase was the result of a higher depletion rate of $13.17 per BOE and higher sales volumes of 437,257 BOE during the three months ended June 30, 2018 as compared to depletion rate of $8.74 per BOE and sales volumes of 155,367 BOE for the same period in 2017. The depletion rate increase by 51% is primarily attributable to 44 PUD locations added to the full cost pool since June 30, 2017.

General and administrative expenses. General and administrative expenses ("G&A") decreased by $8.8 million to $7.4 million for the three months ended June 30, 2018, as compared to $16.1 million for the three months ended June 30, 2017. The decrease of $8.8 million in G&A was primarily attributable to payment of $4.8 million of performance bonuses and $4.1 million fair value of equity award bonuses granted to executive officers in May 2017. No similar bonuses were paid or equity bonus granted during the three months ended June 30, 2018. The G&A for the three months ended June 30, 2018 consisted of $1.6 million for payroll expense, $2.5 million of non-cash stock-based compensation, $1.7 million in legal and other professional fees and $1.6 million in other G&A related expenses.

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

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Variance	%
Production Costs per BOE:				
Production costs	$ 7.69	$ 8.07	$ (0.38)	(5)%
Gathering, processing and transportation	1.78	1.83	(0.05)	(3)%
Production taxes	2.88	1.76	1.12	64 %
General and administrative	23.82	106.04	(82.22)	(78)%
Depreciation, depletion, amortization and accretion	13.88	10.48	3.40	32 %
Total (BOE)	$ 50.05	$ 128.18	$ (78.13)	(61)%
Operating Expenses:				
Production costs	$ 5,760	$ 1,927	$ 3,833	199 %
Gathering, processing and transportation	1,334	437	897	205 %
Production taxes	2,158	420	1,738	414 %
General and administrative	17,844	25,329	(7,485)	(30)%
Depreciation, depletion, amortization and accretion	10,400	2,504	7,896	315 %
Total Operating Expenses	$ 37,496	30,617	6,879	22 %

Production costs. Our production costs increased from $1.9 million, or $8.07 per BOE, for the six months ended June 30, 2017, to $5.8 million, or $7.69 per BOE, for the six months ended June 30, 2018. The significant increase in production costs was primarily due to the increased production volumes during the six months ended June 2018. However, the decrease of $0.38 per BOE in production costs resulted from lower workover and overhead costs per BOE produced.

Gathering, processing and transportation. Our gathering, processing and transportation costs increased by $0.9 million to $1.3 million for the six months ended June 30, 2018 compared to $0.4 million during the same period in 2017. The increase resulted from the impact of higher sales volumes and rate-related increases.

Production taxes. Currently, ad valorem, severance and conservation taxes range from 1% to 13% based on the state and county from which production is derived. The increased in production taxes corresponds to the increase in production revenues during the six months ended June 30, 2018.

Depreciation, depletion, amortization and accretion. Our depreciation, depletion and amortization expense increased by $7.9 million to $10.4 million for the six months ended June 30, 2018, compared to $2.5 million during the same period in 2017. The increase was sales production volumes of 238,865 BOE for the same period in 2017. The depletion rate increase by 51% is primarily attributable to 44 PUD locations added to the full cost pool since June 30, 2017.

General and administrative expenses. G&A decreased by $7.5 million to $17.8 million for the six months ended June 30, 2018, as compared to $25.3 million for the six months ended June 30, 2017. The decrease of $7.5 million in G&A was primarily attributable to payment of $4.8 million of performance bonuses and $4.1 million fair value of equity award bonuses granted to executive officers in May 2017 offset by approximately $1.4 million of severance pay paid to five former employees, of which two were former executive officers, during the six months ended June 30, 2018. No similar bonuses were paid or granted during the six months ended June 30, 2018. The G&A for the six months ended June 30, 2018 consisted of $5.2 million for payroll expense, $5.6 million of non-cash stock-based compensation, $4.6 million in legal and other professional fees and $2.4 million in other G&A related expenses.

Other Expenses

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

	Three Months Ended June 30, 2018	2017	Variance	%
	(In Thousands)			
Other income (expense):				
Other income (expense)	$ —	$ (141)	$ 141	(100)%
Loss from commodity derivatives, net	(2,802)	—	(2,802)	100 %
Fair value change in derivatives	(19,501)	(2,418)	(17,083)	706 %
Interest expense	(8,572)	(6,654)	(1,918)	29 %
Total other income (expenses)	$ (30,875)	$ (9,213)	$ (21,662)	235 %

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 $0.7 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 three months ended June 30, 2018. During the three months ended June 30, 2017, we did not participate in any commodity derivative transactions.

Fair Value Changes in Derivatives. During the three months ended June 30, 2018, the fair value change of $17.1 million included only the fair value change of embedded derivatives for the convertible Second Lien Credit Agreement while during the three months ended June 30, 2017, the $2.4 million fair value change included the fair value changes of various warrant derivatives that were exercised in 2017. The fair value change of $19.5 million recorded during the three months ended June 30, 2018 was primarily attributed to the increase in the Company stock price from $3.97 per share at March 31, 2018 to $5.20 per share at June 30, 2018.

Interest Expense. Interest expense for the three months ended June 30, 2018 was $8.6 million compared to $6.7 million for the months ended June 30, 2017. For the three months ended June 30, 2018, we incurred interest expense of $1.1 million for quarterly interest payments on the $50 million credit facility, $3.5 million of paid-in-kind interest, $4.0 million related to amortized debt discount on our Second Lien Loans and $0.3 million of amortized debt issuance costs. For the three months ended June 30, 2017, we incurred $0.4 million of interest expense and non-cash interest expense that included $1.3 million of paid-in-kind interest and $5.0 million of debt issuance costs.

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

	Six Months Ended June 30, 2018	2017	Variance	%
	(In Thousands)			
Other income (expense):				
Other income (expense)	$ 1	$ (133)	$ 134	(101)%
Loss from commodity derivatives, net	(4,572)	—	(4,572)	100 %
Fair value changes in derivatives	8,887	(2,073)	10,960	(529)%
Loss in fair value changes of conditionally redeemable 6% preferred stock	—	(41)	41	(100)%
Interest expense	(17,660)	(7,427)	(10,233)	138 %
Total other income (expenses)	$ (13,344)	$ (9,674)	$ (3,670)	38 %

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 $1.4 million on settlements and a loss of $3.2 million on unsettled positions as a result of the changes in fair value of the oil commodity derivatives during the six months ended June 30, 2018. During the six months ended June 30, 2017, we did not participate in any commodity derivative transactions.

Fair Value Changes in Derivatives. During the six months ended June 30, 2018, the fair value change of $8.9 million included only the fair value change of embedded derivatives for the convertible Second Lien Credit Agreement while during the six months ended June 30, 2017, the $2.1 million fair value change included the fair value changes of various warrant derivatives that had since been exercised during 2017. The fair value change of $8.9 million recorded during the six months ended June 30, 2018 was primarily attributable to the increase in the Company stock price from $5.11 per share at December 31, 2017 to $5.20 per share at June 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 six months ended June 30, 2018 was $17.7 million compared to $7.4 million for the months ended June 30, 2017. For the six months ended June 30, 2018, we incurred interest expense of $1.8 million for interest payments on the $50 million credit facility and $0.7 million on bridge loan that was paid off during first quarter of 2018, $6.4 million of paid-in-kind interest, $7.9 million related to amortized debt discount and $0.9 million of amortized debt issuance costs. For the six months ended June 30, 2017, we incurred $0.9 million of interest payments and non-cash interest expense which included $1.3 million of paid-in-kind interest and $5.2 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 for the acquisition, development, exploration and exploitation of oil and natural gas properties, in addition to refinancing of debt instruments. We have a significant amount of convertible debt and equity securities outstanding, which upon exercise or conversion, would result in substantial dilution of our common stock. Furthermore, if we sell additional equity or convertible debt securities, such sales could result in further dilution to our existing stockholders and cause the price of our outstanding securities to decline.

We believe our financial position is strong and provides the financial flexibility to fund our currently planned 2018 capital expenditures. During the six months ended June 30, 2018, we raised $185 million in cash, with net proceeds to be used for 2018 capital expenditures, acquisitions, repayment of existing debt and other general corporate purposes.

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 first-lien bridge loan. Approximately $31.8 million in proceeds were used to pay off and retire the First Lien Credit Agreement, and remaining proceeds have been and will be used to fund 2018 capital expenditures, acquisitions and other general corporate purposes, including payment of transaction expenses.

In addition, on January 30, 2018, we entered into a Securities Purchase Agreement with Värde Partners, Inc 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.

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 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.

In July, 2018, we entered into another infrastructure solution including a flow assurance agreement that provides firm takeaway agreement and water gathering transactions. Total 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 option to acquire our existing water infrastructure for the firm transportation and pricing for crude oil and a $5.0 million for prefunded drilling bonus. The Company expects to receive the remaining $5.0 million for both the right-of-way/easement bonus and hitting target of 40,000 barrels per day of produced water during the third quarter of 2018.

Based upon current commodity price expectations for 2018 and 2019, we believe that our cash flow from operations, in addition to financing activity, will be sufficient to fund our drilling and completion operations over the next 12 months, including working capital requirements. We expect to be cash flow neutral in early 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 2018 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.

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

	Six Months Ended June 30,	
	2018	2017
Cash provided by (used in):		
Operating activities	$ 42,210	$ (7,414)
Investing activities	(145,980)	(39,843)
Financing activities	113,706	78,258
Net change in cash, cash equivalents and restricted cash	$ 9,936	$ 31,001

Operating activities. For the six months ended June 30, 2018, net cash provided by operating activities was $42.2 million, compared to net cash $7.4 million used in the same period in 2017. The increase in cash provided by operating activities was primarily attributable to the one-time payment of $35.0 million from Salt Creek Midstream associated with an Option Agreement to provide future gas gathering midstream services and also increased production revenue.

Investing activities. For the six months ended June 30, 2018, net cash used in investing activities was $146.0 million compared to $39.8 million for the same period in 2017. The $146.0 million in cash used in investing activities during the six months ended June 30, 2018 was primarily attributable to the following:

- approximately $77.0 million in drilling and completion costs;
- approximately $41.2 million cash consideration on the acquisition of leasehold acreage in the Delaware Basin in Lea County, New Mexico from OneEnergy Partners Operating, LLC;
- approximately $10.7 million cash consideration on the acquisition of proved and unproved oil and gas properties in Loving and Winkler Counties, Texas from VPD Texas, L.P.; and
- approximately $7.1 million incurred on additional leasehold interests acquired from Anadarko and approximately $10.0 million on other lease bonuses primarily for leases in Winkler County, Texas and Lea County, New Mexico.

Financing activities. For the six months ended June 30, 2018, net cash provided by financing activities was $148.4 million compared to cash provided by financing activities of $78.3 million during the same period in 2017. The $148.4 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 Term Loan;
- $2.0 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 $0.5 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 six months ended June 30, 2018.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks including, risks from changes in commodity prices, interest rate risk and customer credit 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 we receive depend on many factors outside of our control. Oil prices we received during the three and six months ended June 30, 2018, ranged from a low of $49.73 per barrel to a high of $63.49 per barrel. Natural gas prices we received 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 during the three and six months ended June 30, 2018 ranged from a low of $0.49 per gallon to a high of $0.79 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.

To reduce the impact of fluctuations in oil and natural gas prices on the Company's revenues, or 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). As of June 30, 2018, we had hedging arrangements in place on approximately 2000 average WTI BOPD barrels that yield an average floor of $52.71 and a ceiling of $69.36 for the remainder of 2018 and on 1500 Midland-Cushing WTI BOPD barrels with an average cost differential of $5.617 for 2018. 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.

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 June 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 Term Loan Credit Agreement bear 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 exposures to credit risk is through receivables from the sale of our oil and natural gas production of approximately $8.4 million at June 30, 2018, and through receivables from our joint interest partners of approximately $5.0 million together with $4.2 million of accrued unbilled receivables at June 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 June 30, 2018, sales to three customers, Texican Crude & Hydrocarbons, LLC, Lucid Energy Delaware, LLC, and ETC Field Services LLC, accounted for approximately 86%, 12% and 2% of our revenue, respectively. For the six months ended June 30, 2018, sales to these same three customers accounted for approximately 86%, 10% and 4% of our revenue, respectively. For the three months ended June 30, 2017, sales to two customers, Texican Crude & Hydrocarbons, LLC and ETC Field Services LLC, accounted for approximately 79% and 21% of our revenue, respectively. For the six months ended June 30, 2017, sales to these same two customers accounted for approximately 78% and 22% 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 by Rule 13a-15(b) 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(e) and 15d-15(e) under the Exchange Act). Our CEO and CFO have determined that disclosure controls and procedures were ineffective as of June 30, 2018, as the changes described below are still being evaluated.

Changes in internal control over financial reporting

During the six months ended June 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 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 second quarter of 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
April 1 - 30, 2018[2]	253,598	$ 3.97	184,800	—
May 1 - 31, 2018	—	$ —	—	—
June 1 - 30, 2018	—	$ —	—	—
Total	253,598		184,800	—

(1) During the six months ended June 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.

(2) On March 27, 2018, the Company repurchased a total of 68798 shares at an average price of $3.78, 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

Not applicable

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 Annex A of the Company's Definitive Proxy Statement on Schedule 14A, filed on June 1, 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: August 9, 2018	By:	/s/ Ronald D. Ormand
		Ronald D. Ormand Chief Executive Officer (Principal Executive Officer)
Date: August 9, 2018	By:	/s/ Joseph C. Daches
		Joseph C. Daches Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE 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

August 9, 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
Executive Vice President, Chief Financial Officer and Treasurer

August 9, 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 June 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

August 9, 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 June 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
Executive Vice President, Chief Financial Officer and Treasurer

August 9, 2018