UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

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

For the quarterly period ended September 30, 2017

or

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

For the transition period from ______________ to _______________

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

Texas **(State of incorporation)**	**72-1121985** **(IRS Employer Identification Number)**
Nine Greenway Plaza, Suite 300 **Houston, Texas** **(Address of principal executive offices)**	**77046-0908** **(Zip Code)**

(713) 626-8525
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the *preceding* 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T 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, smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☑
Non-accelerated filer (Do not check if a smaller reporting company)	☐	Smaller reporting company	☐
		Emerging growth company	☐

Indicate by check mark whether the registrant is a shell company. Yes ☐ No ☑

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. ☐

As of October 31, 2017, there were 137,821,744 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	September 30, 2017	December 31, 2016
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 106,164	$ 70,236
Receivables:		
Oil and natural gas sales	39,165	43,073
Joint interest	21,877	21,885
Insurance reimbursement	—	30,100
Income taxes	11,623	11,943
Total receivables	72,665	107,001
Prepaid expenses and other assets (Note 1)	15,073	14,504
Total current assets	193,902	191,741
Oil and natural gas properties and other, net - at cost: (Note 1)	555,254	547,053
Restricted deposits for asset retirement obligations	25,339	27,371
Income tax receivables	52,097	52,097
Other assets (Note 1)	60,779	11,464
Total assets	$ 887,371	$ 829,726
Liabilities and Shareholders' Deficit		
Current liabilities:		
Accounts payable	$ 72,197	$ 81,039
Undistributed oil and natural gas proceeds	20,084	26,254
Asset retirement obligations	29,456	78,264
Long-term debt	11,147	8,272
Accrued liabilities (Note 1)	26,550	9,200
Total current liabilities	159,434	203,029
Long-term debt: (Note 2)		
Principal	873,733	873,733
Carrying value adjustments	108,884	138,722
Long term debt, less current portion - carrying value	982,617	1,012,455
Asset retirement obligations, less current portion	275,560	256,174
Other liabilities (Note 1)	67,031	17,105
Commitments and contingencies (Note 9)	—	—
Shareholders' deficit:		
Preferred stock, \$0.00001 par value; 20,000,000 shares authorized; 0 issued at September 30, 2017 and December 31, 2016	—	—
Common stock, \$0.00001 par value; 200,000,000 shares authorized; 140,690,917 issued and 137,821,744 outstanding at September 30, 2017 and 140,543,545 issued and 137,674,372 outstanding at December 31, 2016	1	1
Additional paid-in capital	545,422	539,973
Retained earnings (deficit)	(1,118,527)	(1,174,844)
Treasury stock, at cost; 2,869,173 shares at September 30, 2017 and December 31, 2016	(24,167)	(24,167)
Total shareholders' deficit	(597,271)	(659,037)
Total liabilities and shareholders' deficit	$ 887,371	$ 829,726

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands except per share data) (Unaudited)			
Revenues	$ 110,281	$ 107,403	$ 357,997	$ 284,773
Operating costs and expenses:				
Lease operating expenses	35,134	37,520	106,817	118,611
Production taxes	340	482	1,304	1,378
Gathering and transportation	4,108	5,161	15,635	16,651
Depreciation, depletion, amortization and accretion	36,489	51,500	116,843	172,726
Ceiling test write-down of oil and natural gas properties	—	57,912	—	279,063
General and administrative expenses	15,631	12,692	45,379	45,370
Derivative (gain) loss	2,879	412	(4,765)	2,861
Total costs and expenses	94,581	165,679	281,213	636,660
Operating income (loss)	15,700	(58,276)	76,784	(351,887)
Interest expense:				
Incurred	11,554	23,693	34,284	81,280
Capitalized	—	(75)	—	(520)
Gain on exchange of debt	—	123,960	7,811	123,960
Other (income) expense, net	(41)	(73)	5,073	1,209
Income (loss) before income tax expense (benefit)	4,187	42,139	45,238	(309,896)
Income tax expense (benefit)	5,484	(3,789)	(11,079)	(44,393)
Net income (loss)	$ (1,297)	$ 45,928	$ 56,317	$ (265,503)
Basic and diluted earnings (loss) per common share	$ (0.01)	$ 0.48	$ 0.39	$ (3.25)

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' DEFICIT

	Common Stock Outstanding		Additional Paid-In	Retained Earnings	Treasury Stock		Total Shareholders'
	Shares	Value	Capital	(Deficit)	Shares	Value	Deficit
				(In thousands) (Unaudited)			
Balances at December 31, 2016	137,674	$ 1	$ 539,973	$ (1,174,844)	2,869	$ (24,167)	$ (659,037)
Share-based compensation	148	—	5,449	—	—	—	5,449
Net income	—	—	—	56,317	—	—	56,317
Balances at September 30, 2017	137,822	$ 1	$ 545,422	$ (1,118,527)	2,869	$ (24,167)	$ (597,271)

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2017	2016
	(In thousands) (Unaudited)	
Operating activities:		
Net income (loss)	$ 56,317	$ (265,503)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion, amortization and accretion	116,843	172,726
Ceiling test write-down of oil and natural gas properties	—	279,063
Gain on exchange of debt	(7,811)	(123,960)
Debt issuance costs write-down/amortization of debt items	1,271	2,135
Share-based compensation	5,449	7,642
Derivative (gain) loss	(4,765)	2,861
Cash receipts on derivative settlements	3,924	4,746
Deferred income taxes	321	15,484
Changes in operating assets and liabilities:		
Oil and natural gas receivables	3,906	294
Joint interest receivables	8	4,281
Insurance reimbursements	31,740	—
Income taxes	320	(52,392)
Prepaid expenses and other assets	2,194	(16,128)
Escrow deposit - Apache lawsuit	(49,500)	—
Asset retirement obligation settlements	(56,226)	(56,167)
Accounts payable, accrued liabilities and other	26,329	15,750
Net cash provided by (used in) operating activities	130,320	(9,168)
Investing activities:		
Investment in oil and natural gas properties and equipment	(79,088)	(24,062)
Changes in operating assets and liabilities associated with investing activities	5,679	(37,400)
Proceeds from sales of assets	—	1,500
Purchases of furniture, fixtures and other	(905)	(96)
Net cash used in investing activities	(74,314)	(60,058)
Financing activities:		
Borrowings of long-term debt - revolving bank credit facility	—	340,000
Repayments of long-term debt - revolving bank credit facility	—	(340,000)
Payment of interest on 1.5 Lien Term Loan	(6,170)	—
Payment of interest on 2nd Lien PIK Toggle Notes	(7,335)	—
Payment of interest on 3rd Lien PIK Toggle Notes	(6,201)	—
Issuance of 1.5 Lien Term Loan	—	75,000
Debt exchange/issuance costs	(421)	(17,920)
Other	49	83
Net cash provided by (used in) financing activities	(20,078)	57,163
Increase (decrease) in cash and cash equivalents	35,928	(12,063)
Cash and cash equivalents, beginning of period	70,236	85,414
Cash and cash equivalents, end of period	$ 106,164	$ 73,351

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

Operations. W&T Offshore, Inc. (with subsidiaries referred to herein as "W&T," "we," "us," "our," or the "Company") is an independent oil and natural gas producer with substantially all of its operations offshore in the Gulf of Mexico. The Company is active in the exploration, development and acquisition of oil and natural gas properties. Our interests in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. (on a stand-alone basis, the "Parent Company") and its 100%-owned subsidiary, W & T Energy VI, LLC ("Energy VI").

Interim Financial Statements. The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP") for interim periods and the appropriate rules and regulations of the Securities and Exchange Commission ("SEC"). Accordingly, the condensed consolidated financial statements do not include all of the information and footnote disclosures required by GAAP for complete financial statements for annual periods. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included.

Operating results for interim periods are not necessarily indicative of the results that may be expected for the entire year. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Recent Events. The price we receive for our crude oil, natural gas liquids ("NGLs") and natural gas production directly affects our revenues, profitability, cash flows, liquidity, access to capital, proved reserves and future rate of growth. The average prices of these commodities improved during the nine months ended September 30, 2017 compared to the average prices in the comparable period in 2016. Operating costs were lower for the nine months ended September 30, 2017 on an absolute and on a per barrel oil equivalent ("Boe") basis compared to the operating costs for the same period in 2016. In September 2016, we consummated the Exchange Transaction, as defined and described below in Note 2, which reduced our interest payments during the nine months ended September 30, 2017 compared to the same period in 2016. In addition, the Exchange Transaction extended the maturities on a portion of our debt, although for a portion of the New Debt, as defined and described below, the maturities of two of the new loans will accelerate if certain events do not transpire.

We have continued working to further reduce our operating costs, capital expenditures and costs related to asset retirement obligations ("ARO"). Our 2017 capital expenditure forecast is higher than the capital expenditures incurred during 2016, but it is significantly lower than spending levels incurred during 2015 and 2014. We are in the process of determining our capital expenditure budget for 2018.

As of the filing date of this Form 10-Q, the Company is in compliance with its financial assurance obligations to the Bureau of Ocean Energy Management ("BOEM") and has no outstanding BOEM orders related to financial assurance obligations.

During the second quarter of 2017, a trial court judgment was rendered in Apache Corporation's ("Apache") lawsuit against us. As a result, we deposited $49.5 million with the registry of the court from cash on hand as a first step to allow us to appeal the decision. See Note 9 for additional information.

We have assessed our financial condition, the current capital markets and options given different scenarios of commodity prices. We believe we will have adequate liquidity to fund our operations through December 2018, the period of assessment to qualify as a going concern. However, we cannot predict the potential changes in commodity prices or future bonding requirements, either of which could affect our operations, liquidity levels and compliance with debt covenants.

See our Annual Report on Form 10-K for the year ended December 31, 2016 concerning risks related to our business and events occurring during 2016 and other information and the Notes herein for additional information.

Prepaid Expenses and Other Assets. The amounts recorded in *Prepaid expenses and other assets* are expected to be realized within one year. The major categories are presented in the following table (in thousands):

	September 30, 2017	December 31, 2016
Derivative assets (1)	$ 1,155	$ —
Prepaid/accrued insurance	3,346	2,924
Surety bond unamortized premiums	1,689	2,462
Prepaid deposits related to royalties	6,455	6,237
Other	2,428	2,881
Prepaid expenses and other assets	$ 15,073	$ 14,504

(1) Includes open and closed (and not settled) derivative commodity contracts recorded at fair value.

Oil and Natural Gas Properties and Other, Net – at cost. Oil and natural gas properties and equipment are recorded at cost using the full cost method. There were no amounts excluded from amortization as of the dates presented in the following table (in thousands):

	September 30, 2017	December 31, 2016
Oil and natural gas properties and equipment	$ 8,043,823	$ 7,932,504
Furniture, fixtures and other	21,803	20,898
Total property and equipment	8,065,626	7,953,402
Less accumulated depreciation, depletion and amortization	7,510,372	7,406,349
Oil and natural gas properties and other, net	$ 555,254	$ 547,053

Accrued Liabilities. The major categories recorded in *Accrued liabilities* are presented in the following table (in thousands):

	September 30, 2017	December 31, 2016
Accrued interest	$ 15,037	$ 4,189
Accrued salaries/payroll taxes/benefits	7,152	2,777
Other	4,361	2,234
Total accrued liabilities	$ 26,550	$ 9,200

Other Assets (long-term). The major categories recorded in *Other assets* are presented in the following table (in thousands):

	September 30, 2017	December 31, 2016
Escrow deposit - Apache lawsuit	$ 49,500	$ —
Appeal bond deposits	6,925	6,925
Other	4,354	4,539
Total other assets	$ 60,779	$ 11,464

Other Liabilities (long-term). The major categories recorded in *Other liabilities* are presented in the following table (in thousands):

	September 30, 2017	December 31, 2016
Apache lawsuit	$ 49,500	$ —
Uncertain tax positions including interest/penalties	10,905	10,584
Other	6,626	6,521
Total other liabilities (long-term)	$ 67,031	$ 17,105

Recent Accounting Developments. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09 ("ASU 2014-09"), *Summary and Amendments That Create Revenue from Contracts and Customers (Subtopic 606).* ASU 2014-09 amends and replaces current revenue recognition requirements, including most industry-specific guidance. The revised guidance establishes a five step approach to be utilized in determining when, and if, revenue should be recognized. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. Upon application, an entity may elect one of two methods, either restatement of prior periods presented or recording a cumulative adjustment in the initial period of application (modified retrospective approach). Our current intention is to adopt the standard utilizing the modified retrospective approach. Our evaluation to date is that the adoption of ASU 2014-09 is not expected to have a material impact on our consolidated financial statements. We have not fully completed our analysis. Our disclosures related to revenue will be modified when the new guidance is effective. ASU 2014-09 will be effective for us in the first quarter of 2018.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02 ("ASU 2016-02"), *Leases* (*Subtopic 842*). Under the new guidance, a lessee will be required to recognize assets and liabilities for leases with lease terms of more than 12 months. Consistent with current GAAP, the recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. However, unlike current GAAP, which requires only capital leases to be recognized on the balance sheet, ASU 2016-02 will require both types of leases to be recognized on the balance sheet. ASU 2016-02 also will require disclosures to help investors and other financial statement users to better understand the amount, timing and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative requirements, providing additional information about the amounts recorded in the financial statements. ASU 2016-02 does not apply for leases for oil and gas properties, but does apply to equipment used to explore and develop oil and gas resources. Our current operating leases that will be impacted by ASU 2016-02 are leases for office space in Houston, Texas and New Orleans, Louisiana, although ASU 2016-02 may impact the accounting for leases related to equipment depending on the term of the lease. We currently do not have any leases classified as financing leases nor do we have any leases recorded on the Condensed Consolidated Balance Sheets. ASU 2016-02 is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using the modified retrospective approach. We have not yet fully determined or quantified the effect ASU 2016-02 will have on our financial statements.

In June 2016, the FASB issued Accounting Standards Update No. 2016-13, ("ASU 2016-13"), *Financial Instruments – Credit Losses* (*Subtopic 326*). The new guidance eliminates the probable recognition threshold and broadens the information to consider past events, current conditions and forecasted information in estimating credit losses. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019 and early adoption is permitted for fiscal years beginning after December 15, 2018. We have not yet fully determined or quantified the effect ASU 2016-13 will have on our financial statements.

In August 2016, the FASB issued Accounting Standards Update No. 2016-15, ("ASU 2016-15"), *Statement of Cash Flows (Topic 230) – Classification of Certain Cash Receipts and Cash Payments*. ASU 2016-15 addresses the classification of several items that previously had diversity in practice. Items identified in the new standard which were incurred by us in the past are: (a) debt prepayment or extinguishment costs; (b) contingent consideration made after a business acquisition; and (c) proceeds from settlement of insurance claims. The item described in clause (b) would be the only such item changed under our historical classification in the statement of cash flows (financing vs. investing) and the amount of such change would not have been material; therefore, we do not anticipate the new standard will have a material effect on our financial statements. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017 and early adoption is permitted.

In November 2016, the FASB issued Accounting Standards Update No. 2016-18, ("ASU 2016-18"), *Statement of Cash Flows (Topic 230) – Restricted Cash*. ASU 2016-18 addresses diversity in practice and requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. ASU 2016-18 is expected to change some of the presentation in our statement of cash flows, but not materially impact total cash flows from operating, investing or financing activities. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period.

In August 2017, the FASB issued Accounting Standards Update No. 2017-12, ("ASU 2017-12"), *Derivatives and Hedging (Topic 815) – Targeted Improvements to Accounting for Hedging Activities*. The amendments in ASU 2017-12 require an entity to present the earnings effect of the hedging instrument in the same income statement line in which the earning effect of the hedged item is reported. This presentation enables users of financial statements to better understand the results and costs of an entity's hedging program. Also, relative to current GAAP, this approach simplifies the financial statement reporting for qualifying hedging relationships. As we do not designate our commodity derivative positions as qualifying hedging instruments, our assessment is this amendment will not impact the presentation of the changes in fair values of our commodity derivative instruments on our financial statements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2019 and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted, including adoption in an interim period.

2. Long-Term Debt

The components of our long-term debt are presented in the following table (in thousands):

	September 30, 2017			December 31, 2016		
	Principal	Adjustments to Carrying Value (1)	Carrying Value	Principal	Adjustments to Carrying Value (1)	Carrying Value
11.00% 1.5 Lien Term Loan, due November 2019:						
Principal	$ 75,000	$ —	$ 75,000	$ 75,000	$ —	$ 75,000
Future interest payments	—	17,652	17,652	—	23,823	23,823
Subtotal	75,000	17,652	92,652	75,000	23,823	98,823
9.00 % Second Lien Term Loan, due May 2020:	300,000	—	300,000	300,000	—	300,000
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020:						
Principal	163,007	—	163,007	163,007	—	163,007
Future payments-in-kind	—	14,506	14,506	—	24,048	24,048
Future interest payments	—	34,873	34,873	—	36,850	36,850
Subtotal	163,007	49,379	212,386	163,007	60,898	223,905
8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021:						
Principal	145,897	—	145,897	145,897	—	145,897
Future payments-in-kind	—	18,618	18,618	—	26,844	26,844
Future interest payments	—	38,682	38,682	—	40,705	40,705
Subtotal	145,897	57,300	203,197	145,897	67,549	213,446
8.50% Unsecured Senior Notes, due June 2019	189,829	—	189,829	189,829	—	189,829
Debt premium, discount, issuance costs, net of amortization	—	(4,300)	(4,300)	—	(5,276)	(5,276)
Total long-term debt	873,733	120,031	993,764	873,733	146,994	1,020,727
Current maturities of long-term debt (2)	—	11,147	11,147	—	8,272	8,272
Long term debt, less current maturities	$ 873,733	$ 108,884	$ 982,617	$ 873,733	$ 138,722	$ 1,012,455

(1) Future interest payments and future payments-in-kind ("PIK") are recorded on an undiscounted basis.
(2) Future interest payments on the 1.5 Lien Term Loan and Second Lien PIK Toggle Notes due within twelve months.

Exchange Transaction

On September 7, 2016, we consummated a transaction whereby we exchanged approximately $710.2 million in aggregate principal amount, or 79%, of our 8.500% Senior Notes, due June 15, 2019 (the "Unsecured Senior Notes") for: (i) $159.8 million in aggregate principal amount of 9.00%/10.75% Senior Second Lien PIK Toggle Notes, due May 15, 2020, (the "Second Lien PIK Toggle Notes"); (ii) $142.0 million in aggregate principal amount of 8.50%/10.00% Senior Third Lien PIK Toggle Notes, due June 15, 2021, (the "Third Lien PIK Toggle Notes"); and (iii) 60.4 million shares of our common stock (collectively, the "Debt Exchange"). At the same time on closing on the Debt Exchange, we closed on a $75.0 million, 11.00% 1.5 Lien Term Loan, due November 15, 2019, (the "1.5 Lien Term Loan") with the largest holder of our Unsecured Senior Notes (collectively with the Debt Exchange, the "Exchange Transaction"). We accounted for the Exchange Transaction as a Troubled Debt Restructuring pursuant to the guidance under Accounting Standard Codification 470-60, *Troubled Debt Restructuring* ("ASC 470-60"). Under ASC 470-60, the carrying value of the newly issued Second Lien PIK Toggle Notes, Third Lien PIK Toggle Notes and 1.5 Lien Term Loan (the "New Debt") is measured using all future undiscounted payments (principal and interest); therefore, no interest expense has been recorded for the New Debt in the Condensed Consolidated Statements of Operations since September 7, 2016. Additionally, no interest expense related to the New Debt will be recorded in future periods as payments of interest on the New Debt will be recorded as a reduction in the carrying amount; thus, our reported interest expense will be significantly less than the contractual interest payments through the terms of the New Debt. Under ASC 470-60, payments related to the New Debt are reported in the financing section of the Condensed Consolidated Statements of Cash Flows.

A gain of $124.0 million was initially recognized related to the Exchange Transaction for the three and nine month periods ended September 30, 2016. Under ASC 470-60, a gain was recognized as the sum of (i) the future undiscounted payments (principal and interest) related to the New Debt, (ii) the fair value of the common stock issued and (iii) deal transaction costs of $18.9 million was less than the sum of (iv) the carrying value of the Unsecured Senior Notes exchanged and (v) the funds received from the 1.5 Lien Term Loan. The shares of common stock issued were valued at $1.76 per share, which was the closing price on September 7, 2016. The effect on basic and diluted earnings per share for the three and nine months ended September 30, 2016 was $1.33 per share and $1.52 per share, respectively, which assumes the gain would not affect our income tax benefit for either time period.

The funds received from the 1.5 Lien Term Loan were used to pay transaction costs related to the Exchange Transaction and to pay down borrowings on the revolving bank credit facility. The balance of the borrowings on the revolving bank credit facility was paid down from available cash.

During the second quarter of 2017, interest on the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes was paid in cash rather than in kind. As a result of the cash interest payment, an $8.2 million net reduction was recorded to long-term debt on the Condensed Consolidated Balance Sheet and the offset to *Gain on exchange of debt* in the Condensed Consolidated Statement of Operations. We anticipate the remaining eligible interest payments will be made in kind versus paid in cash. For the nine months ended September 30, 2017, $0.4 million of additional expense was recorded to *Gain on exchange of debt* for differences between actual and estimated transaction expenses. The effect of these transactions on basic and diluted earnings per share for the nine months ended September 30, 2017 was $0.06 per share, which assumes the net gain would not affect income tax benefit for that period.

The primary terms of our long-term debt following the Exchange Transaction are described below.

Credit Agreement

The Fifth Amended and Restated Credit Agreement (as amended, the "Credit Agreement"), provides a revolving bank credit facility. The primary items of the Credit Agreement are as follows, with certain terms defined under the Credit Agreement:

- The borrowing base is $150.0 million.
- Letters of credit may be issued in amounts up to $150.0 million, provided availability under the revolving bank credit facility exists.
- The First Lien Leverage Ratio limit is 2.00 to 1.00.

- The Current Ratio must be greater than 1.00 to 1.00.
- We are required to have deposit accounts only with banks under the Credit Agreement with certain exceptions.
- We may not have unrestricted cash balances above $35.0 million if outstanding balances on the revolving bank credit agreement (including letters of credit) are greater than $5.0 million.
- Borrowings primarily are executed as Eurodollar Loans, and the applicable margins range from 3.00% to 4.00%.
- The commitment fee is 50 basis points for all levels of utilization.
- The Credit Agreement terminates on November 8, 2018.

Availability under our revolving bank credit facility is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. The 2017 spring redetermination reaffirmed the borrowing base amount of $150.0 million. Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. The revolving bank credit facility is secured and is collateralized by a first priority lien on substantially all of our oil and natural gas properties.

The Credit Agreement contains various customary covenants for certain financial tests, as defined in the Credit Agreement and are measured as of the end of each quarter, and for customary events of default. The customary events of default include: (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due; (ii) bankruptcy or insolvency with respect to the Company or any of its subsidiaries guaranteeing borrowings under the revolving bank credit facility; or (iii) a change of control. The Credit Agreement contains cross-default clauses with the other long-term debt agreements, and such agreements contain similar cross-default clauses with the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of September 30, 2017.

As of September 30, 2017 and December 31, 2016, we did not have any borrowings outstanding and had $0.3 million and $0.5 million, respectively, of letters of credit outstanding under the revolving bank credit facility. Availability as of September 30, 2017 was $149.7 million.

1.5 Lien Term Loan

As part of the Exchange Transaction, we entered into the 1.5 Lien Term Loan on September 7, 2016 with a maturity date of November 15, 2019. The maturity date will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes have not been extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Interest accrues at 11.00% per annum and is payable quarterly in cash. The holder of the 1.5 Lien Term Loan was the largest holder of our Unsecured Senior Notes prior to the Exchange Transaction. The 1.5 Lien Term Loan is secured by a 1.5 priority lien on all of our assets pledged under the Credit Agreement. The lien securing the 1.5 Lien Term Loan is subordinate to the liens securing the Credit Agreement and has priority above the liens securing the Second Lien Term Loan (defined below), the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes. All future undiscounted cash flows have been included in the carrying value under ASC 470-60. Current maturities of long-term debt include the cash interest payable for the 1.5 Lien Term Loan payable in the next 12 months. The 1.5 Lien Term Loan contains various covenants that limit, among other things, our ability to: (i) pay cash dividends; (ii) repurchase our common stock; (iii) sell our assets; (iv) make certain loans or investments; (v) merge or consolidate; (vi) enter into certain liens; (vii) create liens that secure debt; and (viii) enter into transactions with affiliates. We were in compliance with all applicable covenants as of September 30, 2017.

Second Lien Term Loan

In May 2015, we entered into the 9.00% Term Loan (the "Second Lien Term Loan"), which bears an annual interest rate of 9.00%. The Second Lien Term Loan was issued at a 1.0% discount to par, matures on May 15, 2020 and is recorded at its carrying value consisting of principal, unamortized discount and unamortized debt issuance costs. Interest on the Second Lien Term Loan is payable in arrears semi-annually on May 15 and November 15. The estimated annual effective interest rate on the Second Lien Term Loan is 9.6%, which includes amortization of debt issuance costs and discounts. The Second Lien Term Loan is secured by a second-priority lien on all of our assets that are secured under the Credit Agreement. The Second Lien Term Loan is effectively subordinate to the Credit Agreement and the 1.5 Lien Term Loan (discussed above) and is effectively *pari passu* with the Second Lien PIK Toggle Notes (discussed below). The Second Lien Term Loan contains covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with all applicable covenants as of September 30, 2017.

Second Lien PIK Toggle Notes

As part of the Exchange Transaction, we issued Second Lien PIK Toggle Notes on September 7, 2016 with a maturity date of May 15, 2020. Cash interest accrues at 9.00% per annum and is payable on May 15 and November 15 of each year. The Second Lien PIK Toggle Notes contain provisions whereby certain semi-annual interest is added to the principal amount through payment-in-kind instead of being paid in cash in the then current semi-annual period. For the initial interest period ending November 15, 2016, interest could only be paid-in-kind at the annual rate of 10.75%. For interest periods through March 7, 2018, if we so elect, we have the option to pay all or a portion of interest in kind at a rate of 10.75% per annum. For the six month interest period ending May 15, 2017, we paid the interest payment in cash rather than using the payment-in-kind provision. The Second Lien PIK Toggle Notes are secured by a second-priority lien on all of our assets that are pledged under the Credit Agreement. The Second Lien PIK Toggle Notes are effectively subordinate to the Credit Agreement and the 1.5 Lien Term Loan (discussed above) and are effectively *pari passu* with the Second Lien Term Loan (discussed above). For purposes of determining the carrying amount under ASC 470-60, we anticipate the remaining eligible interest payments will be paid in kind versus paid in cash. When the PIK option is utilized, the principal amount of the notes increases. Current maturities of long-term debt include the cash interest payable for the Second Lien PIK Toggle Notes for the stub period of March 7, 2018 to May 15, 2018. The Second Lien PIK Toggle Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with all applicable covenants as of September 30, 2017.

Third Lien PIK Toggle Notes

As part of the Exchange Transaction, we issued Third Lien PIK Toggle Notes on September 7, 2016 with a maturity date of June 15, 2021. The maturity date will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes have not been extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Cash interest accrues at 8.50% per annum and is payable on June 15 and December 15 of each year. The Third Lien PIK Toggle Notes contain interest provisions whereby certain semi-annual interest is added to the principal amount through payment-in-kind instead of being paid in cash in the then current semi-annual period. For the initial interest period ending December 15, 2016, interest could only be paid in kind at the annual rate of 10.00%. For interest periods through September 7, 2018, if we so elect, we have the option to pay all or a portion of interest in kind at a rate of 10.00% per annum. For the six month interest period ending June 15, 2017, we paid the interest payment in cash rather than using the payment-in-kind provision. The Third Lien PIK Toggle Notes are secured by a third-priority lien on all of our assets that are secured under the Credit Agreement. The Third Lien PIK Toggle Notes are effectively subordinate to the Second Lien Term Loan and the Second Lien PIK Toggle Notes. For purposes of determining the carrying amount under ASC 470-60, we anticipate the remaining eligible interest payments will be paid in kind versus paid in cash. When the PIK option is utilized, the principal amount of the notes increases. The Third Lien PIK Toggle Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with all applicable covenants as of September 30, 2017.

Unsecured Senior Notes

Our outstanding Unsecured Senior Notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019, were recorded at their carrying value, which includes unamortized debt premium and unamortized debt issuance costs. Interest on the Unsecured Senior Notes is payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the Unsecured Senior Notes is 8.3%, which includes amortization of premiums and debt issuance costs. The Unsecured Senior Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with all applicable covenants as of September 30, 2017.

For information about fair value measurements for our long-term debt, refer to Note 3.

3. Fair Value Measurements

We measure the fair value of our open derivative financial instruments by applying the income approach, using models with inputs that are classified within Level 2 of the valuation hierarchy. The inputs used for the fair value measurement of our derivative financial instruments are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads, credit risk and published commodity futures prices. The fair value of the 1.5 Lien Term Loan was estimated using the carrying value of the principal as no market has developed and the holder of the 1.5 Lien Term Loan was the largest holder of our Unsecured Senior Notes prior to the Exchange Transaction. The fair values of our Second Lien Term Loan, Second Lien PIK Toggle Notes, Third Lien PIK Toggle Notes and Unsecured Senior Notes were based on quoted prices, although the market is not an active market; therefore, the fair value is classified within Level 2.

The following table presents the fair value of our open derivatives and long-term debt, all of which are classified as Level 2 within the valuation hierarchy (in thousands):

	September 30, 2017		December 31, 2016	
	Assets	Liabilities	Assets	Liabilities
Derivatives - open contracts	$ 841	$ —	$ —	$ —
11.00% 1.5 Term Loan, due November 2019 (1)	—	75,000	—	75,000
9.00% Second Lien Term Loan, due May 2020 (1)	—	267,000	—	255,000
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020 (1)	—	143,446	—	122,255
8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021 (1)	—	106,505	—	80,243
8.50% Unsecured Senior Notes, due June 2019 (1)	—	167,050	—	123,389

(1) The long-term debt items are reported on the Condensed Consolidated Balance Sheets at their carrying value as described in Note 2.

4. Asset Retirement Obligations

Our ARO primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives.

A summary of the changes to our ARO is as follows (in thousands):

Balance, December 31, 2016	$ 334,438
Liabilities settled	(56,226)
Accretion of discount	12,820
Revisions of estimated liabilities (1)	13,984
Balance, September 30, 2017	305,016
Less current portion	29,456
Long-term	$ 275,560

(1) Revisions were primarily related to changes from sustained casing pressure at four fields. Wells that experience sustained casing pressure require more days and greater work scope to complete the abandonment project.

5. Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and, from time to time, we use various derivative instruments to manage our exposure to this commodity price risk from sales of our oil and natural gas. All of the derivative counterparties are also lenders or affiliates of lenders participating in our revolving bank credit facility. We are exposed to credit loss in the event of nonperformance by the derivative counterparties; however, we currently anticipate that each of our derivative counterparties will be able to fulfill their contractual obligations. Additional collateral is not required by us due to the derivative counterparties' collateral rights as lenders, and we do not require collateral from our derivative counterparties.

We have elected not to designate our commodity derivative contracts as hedging instruments; therefore, all changes in the fair value of derivative contracts were recognized currently in earnings during the periods presented. The cash flows of all of our commodity derivative contracts are included in *Net cash provided by operating activities* on the Condensed Consolidated Statements of Cash Flows.

For information about fair value measurements, refer to Note 3.

Commodity Derivatives

As of September 30, 2017, we had open crude oil and natural gas derivative contracts for a portion of our anticipated future production for the remainder of 2017. These contracts were entered into during the first quarter of 2017. For crude oil, we entered into two types of contracts. The first type is a swap contract, where we either receive or pay depending on whether the crude oil price is below or above the contract price. The second type is known as "two-way collar" consisting of a purchased put option and a sold call option. These two-way collars provide price risk protection if commodity prices fall below certain levels, but may limit incremental income from favorable price movements above certain limits. The crude oil contracts are based on West Texas Intermediate ("WTI") crude oil prices as quoted off the New York Mercantile Exchange ("NYMEX"). For natural gas, we entered into "two-way collar" contracts. The natural gas contracts are based on Henry Hub natural gas prices as quoted off the NYMEX. The strike prices of both the oil and natural gas two-way collar contracts were set so that the contracts were premium neutral ("costless"), which means no net premiums were paid to or received from a counterparty. Settlement occurs monthly using the per day notional quantity. As of December 31, 2016, we did not have any open derivative contracts.

As of September 30, 2017, our open commodity derivative contracts were as follows:

Crude Oil: Swap, Priced off WTI (NYMEX)

Termination Period		Notional (1) Quantity (Bbls/day)	Notional (1) Quantity (Bbls)	Strike Price
2017	4th Quarter	1,000	92,000	$ 55.25

Crude Oil: Two-way collars, Priced off WTI (NYMEX)

Termination Period		Notional (1) Quantity (Bbls/day)	Notional (1) Quantity (Bbls)	Weighted Average Contract Price	
				Put Option (Bought)	Call Option (Sold)
2017	4th Quarter	4,000	368,000	$ 50.00	$ 60.15

Natural Gas: Two-way collars, Priced off Henry Hub (NYMEX)

Termination Period		Notional (1) Quantity (MMBtu's/day)	Notional (1) Quantity (MMBtu's)	Weighted Average Contract Price	
				Put Option (Bought)	Call Option (Sold)
2017	4th Quarter (2)	30,000	1,830,000	$ 3.07	$ 3.96

(1) Volume Measurements: Bbls – barrelsMMBtu's – million British Thermal Units.

(2) The natural gas derivative contracts are priced and closed in the last week prior to the related production month. Natural gas derivative contracts related to October 2017 production were priced and closed in September 2017 and are not included in the above table as these were not open derivative contracts as of September 30, 2017.

Our open and closed (not settled) commodity derivative contracts were recorded within the line *Prepaid expenses and other assets* on the Condensed Consolidated Balance Sheets summarized in the following table (in thousands):

	September 30, 2017	December 31, 2016
Open contracts	$ 841	$ —
Closed contracts - not settled	314	—
Total contracts	$ 1,155	$ —

Changes in the fair value and settlements of our commodity derivative contracts were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Derivative (gain) loss	$ 2,879	$ 412	$ (4,765)	$ 2,861

Cash receipts, net, on commodity derivative contract settlements are included within *Net cash provided by (used in) operating activities* on the Condensed Consolidated Statements of Cash Flows and were as follows (in thousands):

	Nine Months Ended September 30,	
	2017	2016
Cash receipts on derivative settlements, net	$ 3,924	$ 4,746

Offsetting Commodity Derivatives

All our commodity derivative contracts permit netting of derivative gains and losses upon settlement. In general, the terms of the contracts provide for offsetting of amounts payable or receivable between us and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same commodity. If an event of default were to occur causing an acceleration of payment under our revolving bank credit facility, that event may also trigger an acceleration of settlement of our derivative instruments. If we were required to settle all of our open derivative contracts, we would be able to net payments and receipts per counterparty pursuant to the derivative contracts. Although our derivative contracts allow for netting, which would allow for recording assets and liabilities per counterparty on a net basis, we have historically accounted for our derivative contracts on a gross basis per contract as either an asset or liability.

6. Share-Based Compensation and Cash-Based Incentive Compensation

Awards to Employees. In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (the "Plan") was approved by our shareholders, and amendments to the Plan were approved by our shareholders in May 2013, May 2016 and May 2017. The May 2017 amendment increased the number of shares available in the Plan by 7,700,000 shares. As allowed by the Plan, during the nine months ended September 30, 2017 and the years 2016 and 2015, the Company granted restricted stock units ("RSUs") to certain of its employees. RSUs are a long-term compensation component of the Plan, which are granted to certain employees, and are subject to adjustments at the end of the applicable performance period based on the results of certain predetermined criteria. In addition to share-based compensation, the Company may grant to its employees cash-based incentive awards, which are a short-term component of the Plan and are typically based on the Company and the employee achieving certain pre-defined performance criteria.

As of September 30, 2017, there were 14,633,337 shares of common stock available for issuance in satisfaction of awards under the Plan. The shares available for issuance are reduced when RSUs are settled in shares of common stock, net of withholding tax. The Company has the option at vesting to settle RSUs in stock or cash, or a combination of stock and cash. Prior to 2017, only shares of common stock were used to settle vested RSUs. For the nine months ended September 30, 2017, cash was used to settle vested RSUs related to the retirement of an executive officer. The Company plans to settle RSUs that vest in the future using shares of common stock.

RSUs currently outstanding related to the 2016 and 2015 grants have been adjusted for performance achieved against predetermined criteria for the applicable performance year. These RSUs continue to be subject to employment-based criteria and vesting occurs in December of the second year after the grant. The RSUs related to the 2017 grants are subject to performance-based criteria and employment-based criteria. See the second table below for potential vesting by year.

We recognize compensation cost for share-based payments to employees over the period during which the recipient is required to provide service in exchange for the award. Compensation cost is based on the fair value of the equity instrument on the date of grant. The fair values for the RSUs granted during 2017, 2016 and 2015 were determined using the Company's closing price on the grant date. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that are expected to actually vest.

All RSUs awarded are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restricted period.

A summary of activity related to RSUs during the nine months ended September 30, 2017 is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, December 31, 2016	6,107,248	$ 2.73
Granted	2,095,851	2.77
Vested	(323,870)	2.73
Forfeited	(343,918)	2.76
Nonvested, September 30, 2017	7,535,311	2.74

For the outstanding RSUs issued to the eligible employees as of September 30, 2017, vesting is expected to occur as follows:

	Restricted Stock Units
2017	2,087,768
2018	3,443,731
2019	2,003,812
Total	7,535,311

The fair value of RSUs granted during the nine months ended September 30, 2017 was $5.8 million based on the closing price of the Company's common stock on the date of grant.

Awards to Non-Employee Directors. Under the Director Compensation Plan, shares of restricted stock ("Restricted Shares") have been granted to the Company's non-employee directors. Grants to non-employee directors were made during the nine months ended September 30, 2017, and the years 2016 and 2015. As of September 30, 2017, there were 170,524 shares of common stock available for issuance in satisfaction of awards under the Director Compensation Plan. The shares available are reduced when Restricted Shares are granted.

We recognize compensation cost for share-based payments to non-employee directors over the period during which the recipient is required to provide service in exchange for the award. Compensation cost is based on the fair value of the equity instrument on the date of grant. The fair values for the Restricted Shares granted were determined using the Company's closing price on the grant date. No forfeitures were estimated for the non-employee directors' awards.

The Restricted Shares are subject to service conditions and vesting occurs at the end of specified service periods unless approved by the Board of Directors. Restricted Shares cannot be sold, transferred or disposed of during the restricted period. The holders of Restricted Shares generally have the same rights as a shareholder of the Company with respect to such Restricted Shares, including the right to vote and receive dividends or other distributions paid with respect to the Restricted Shares.

A summary of activity related to Restricted Shares during the nine months ended September 30, 2017 is as follows:

	Restricted Shares	
	Shares	Weighted Average Grant Date Fair Value Per Share
Nonvested, December 31, 2016	161,296	$ 3.47
Granted	147,372	1.90
Vested	(62,140)	4.51
Nonvested, September 30, 2017	246,528	2.27

For the outstanding Restricted Shares issued to the non-employee directors as of September 30, 2017, vesting is expected to occur as follows:

	Restricted Shares
2018	106,240
2019	91,164
2020	49,124
Total	246,528

The fair value of Restricted Shares granted during the nine months ended September 30, 2017 was $0.3 million based on the closing price of the Company's common stock on the date of grant.

Share-Based Compensation. Share-based compensation expense is recorded in the line *General and administrative expenses* in the Condensed Consolidated Statements of Operations. A summary of incentive compensation expense under share-based payment arrangements and the related tax benefit is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Share-based compensation expense from:				
Restricted stock units	$ 1,914	$ 2,451	$ 6,114	$ 7,339
Restricted Shares	70	70	210	303
Total	$ 1,984	$ 2,521	$ 6,324	$ 7,642
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$ 694	$ 883	$ 2,213	$ 2,675

Unrecognized Share-Based Compensation. As of September 30, 2017, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $7.8 million and $0.4 million, respectively. Unrecognized share-based compensation expense will be recognized through November 2019 for RSUs and April 2019 for Restricted Shares.

Cash-Based Incentive Compensation. As defined by the Plan, annual incentive awards may be granted to eligible employees and are typically payable in cash. These awards are performance-based awards consisting of one or more business or individual performance criteria and a targeted level or levels of performance with respect to each such criterion. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year.

During the nine months ended September 30, 2017, and the years 2016 and 2015, the Company issued cash-based incentive awards. In addition to being performance-based awards related to respective 2017, 2016 and 2015 criteria, the payment of such awards is contingent on the Company achieving the following financial condition on or before December 31, 2019, December 31, 2018 and December 31, 2017, respectively: Adjusted EBITDA less Interest Expense, as reported by the Company in its announced Earnings Release with respect to the end of any fiscal quarter plus three preceding quarters, exceeds $200.0 million for the 2017 awards and exceeds $300.0 million for the 2016 and 2015 awards. As the Company did not achieve the financial condition for the 2016 and 2015 awards up through September 30, 2017, and we do not estimate the Company will achieve the financial condition within the respective measurement period, no amounts have been recognized to date related to the 2015 and 2016 awards. For the 2017 awards, amounts were recognized as reported in the table below as it is estimated that the Company will achieve some of the performance-based criteria and will achieve the financial condition within the respective measurement period.

A summary of compensation expense related to share-based awards and cash-based awards is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Share-based compensation included in:				
General and administrative expenses	$ 1,984	$ 2,521	$ 6,324	$ 7,642
Cash-based incentive compensation included in:				
Lease operating expense	930	—	1,324	—
General and administrative expenses	2,287	—	3,291	—
Total charged to operating income	$ 5,201	$ 2,521	$ 10,939	$ 7,642

7. Income Taxes

Our income tax expense for the three months ended September 30, 2017 was $5.5 million and our income tax benefit for the nine months ended September 30, 2017 was $11.1 million. Our income tax benefit for the three and nine months ended September 30, 2016 was $3.8 million and $44.4 million, respectively. Under GAAP, we are required to use the annualized effective tax rate method in computing income tax expense or benefit for interim periods. Somewhat improving commodity prices and a relatively lower forecasted spend for plug and abandonment work in 2017 revised our forecast, which required us to reduce the amount of benefits previously recorded in the first half of 2017 under the annualized effective tax rate method. Our effective tax rate was not meaningful for any period presented. The income tax benefit for all periods presented relates to net operating loss (“NOL”) carryback claims made pursuant to Internal Revenue Code (“IRC”) Section 172(f) (related to rules for “specified liability losses”), which permit certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years.

During the nine months ended September 30, 2017, we received $11.9 million of income tax refunds and made $0.2 of income tax payments. During the nine months ended September 30, 2016, we received $7.8 million of income tax refunds and made income tax payments of $0.3 million.

As of September 30, 2017, we recorded current income tax receivables of $11.6 million and non-current income tax receivables of $52.1 million. As of December 31, 2016, we recorded current income tax receivables of $11.9 million and non-current income tax receivables of $52.1 million. The current income tax receivables as of September 30, 2017 relates to our estimated NOL carryback claim for 2017. The non-current income tax receivables relates to our NOL claims for the years 2012, 2013 and 2014 that were carried back to prior years. These carryback claims are made pursuant to IRC Section 172(f) described above. The refund claims related to the years 2012, 2013 and 2014 will require a review by the Congressional Joint Committee on Taxation and are accordingly classified as non-current.

As of September 30, 2017 and December 31, 2016, our valuation allowance was $274.5 million and $290.2 million, respectively, related to Federal, Louisiana and Alabama NOLs and other deferred assets. Net deferred tax assets were recorded related to NOLs and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or NOLs are deductible. In addition, the realization depends on the ability to carryback certain items to prior years for refunds of taxes previously paid. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the nine months ended September 30, 2017 and 2016, we recorded immaterial amounts of accrued interest expense related to our unrecognized tax benefit.

The tax years 2013 through 2016 remain open to examination by the tax jurisdictions to which we are subject.

8. Earnings/ (Loss) Per Share

The following table presents the calculation of basic and diluted earnings (loss) per common share (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net income (loss)	$ (1,297)	$ 45,928	$ 56,317	$ (265,503)
Less portion allocated to nonvested shares	—	1,689	2,349	—
Net income (loss) allocated to common shares	$ (1,297)	$ 44,239	$ 53,968	$ (265,503)
Weighted average common shares outstanding	137,575	92,243	137,547	81,748
Basic and diluted earnings (loss) per common share	$ (0.01)	$ 0.48	$ 0.39	$ (3.25)
Shares excluded due to being anti-dilutive (weighted-average)	7,709	—	—	3,833

9. Contingencies

Supplemental Bonding Requirements by the BOEM. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to satisfy lease obligations, including decommissioning activities on the OCS. As of the filing date of this Form 10-Q, the Company is in compliance with its financial assurance obligations to the BOEM and has no outstanding BOEM orders related to assurance obligations. W&T and other offshore Gulf of Mexico producers may in the ordinary course receive future demands for financial assurances from the BOEM as the BOEM continues to reevaluate its requirements for financial assurances.

In July 2016, the BOEM issued Notice to Lessees #2016-N01 ("NTL #2016-N01") to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional financial assurances may be required for OCS leases, rights-of-way or rights-of-use and easements. NTL #2016-N01 became effective in September 2016 and superseded and replaced NTL #2008-N07. During the third quarter of 2017, the BOEM rescinded its four orders issued in the first quarter of 2016 that instructed the Company to provide additional supplemental bonding of $260.8 million.

Surety Bond Collateral. The issuers of surety bonds in some cases have requested and received additional collateral related to surety bonds for plugging and abandonment activities. We may be required to post collateral at any time pursuant to the terms of our agreement with various sureties under our existing bonds, if they so demand at their discretion. We did not receive any collateral demands from surety bond providers during the nine months ended September 30, 2017.

Apache Lawsuit. On December 15, 2014, Apache filed a lawsuit against the Company alleging that W&T breached the joint operating agreement related to, among other things, the abandonment of three deepwater wells in the Mississippi Canyon ("MC") area of the Gulf of Mexico. A trial court judgment was rendered from the U.S. District Court for the Southern District of Texas on May 31, 2017 directing the Company to pay Apache $43.2 million, plus $6.3 million in prejudgment interest, attorney's fees and costs assessed in the judgment. We have commenced the process to appeal the trial court judgment in this lawsuit.

The dispute relates to Apache's use of drilling rigs instead of a previously contracted intervention vessel for the plugging and abandonment work. We contended that the costs to use the drilling rigs were unnecessary and unreasonable, and that Apache chose to use the rigs without W&T's consent because they otherwise would have been idle at Apache's expense. We believe the use of the rigs was in bad faith, as found by the jury, and that such conduct caused W&T not to comply with the applicable joint operating agreement, particularly since another vessel had been contracted by Apache for the abandonment a year in advance. We had previously paid $24.9 million to Apache as an undisputed amount for the plug and abandonment work.

On October 28, 2016, the jury made the following findings:

1. W&T failed to comply with the contract by failing to pay its proportionate share of the costs to plug and abandon the MC 674 wells.
2. The amount of money to compensate Apache for W&T's failure to pay its proportionate share of the costs to plug and abandon the MC 674 wells was $43.2 million.
3. The $43.2 million referred to in #2 should be offset by $17.0 million.
4. Apache acted in bad faith thereby causing W&T to not comply with the contract.

In June 2017, in order to stay execution of the judgment, and pending the disposition of post judgment motions, we deposited $49.5 million with the registry of the court. This amount is recorded in *Other assets* (long-term) with a corresponding reduction to *Cash and cash equivalents* on the Condensed Consolidated Balance Sheet. Although we are appealing the decision, based solely on the decision rendered, we have recorded $49.5 million in *Other liabilities* (long-term) and $43.2 million in capitalized ARO included in *Oil and natural gas properties and other, net* on the Condensed Consolidated Balance Sheet as of September 30, 2017 and have recognized $6.3 million of expense included in *Other (income) expense, net* on the Condensed Consolidated Statement of Operations for the nine months ended September 30, 2017.

Appeal with the Office of Natural Resources Revenue ("ONRR"). In 2009, we recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited our calculations and support related to this usage fee, and in 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue in 2010 to reflect this disallowance; however, we disagree with the position taken by the ONRR. We filed an appeal with the ONRR, which was denied in May 2014. On June 17, 2014, we filed an appeal with the Interior Board of Land Appeals ("IBLA") under the Department of the Interior. On January 27, 2017, the IBLA affirmed the decision of the ONRR requiring W&T to pay approximately $4.7 million in additional royalties. We filed an appeal of the IBLA decision on July 25, 2017 in the U.S. District Court for the Eastern District of Louisiana.

Royalties – "Unbundling" Initiative. The ONRR has publicly announced an "unbundling" initiative to revise the methodology employed by producers in determining the appropriate allowances for transportation and processing costs that are permitted to be deducted in determining royalties under Federal oil and gas leases. The ONRR's initiative requires re-computing allowable transportation and processing costs using revised guidance from the ONRR going back 84 months for every gas processing plant that processed our gas. In the second quarter of 2015, pursuant to the initiative, we received requests from the ONRR for additional data regarding our transportation and processing allowances on natural gas production related to a specific processing plant. We also received a preliminary determination notice from the ONRR asserting that our allocation of certain processing costs and plant fuel use at another processing plant was not allowed as deductions in the determination of royalties owed under Federal oil and gas leases. We have submitted revised calculations covering certain plants and time periods to the ONRR. As of the filing date of this Form 10-Q, we have not received a response from the ONRR related to our submissions. These open ONRR unbundling reviews, and any further similar reviews, could ultimately result in an order for payment of additional royalties under our Federal oil and gas leases for current and prior periods. For the nine months ended September 30, 2017, we have made additional royalty payments of $1.2 million. We are not able to determine the range of any additional royalties or, if and when assessed, whether such amounts would be material.

Notices of Proposed Civil Penalty Assessment. As of September 30, 2017, we had six open civil penalties issued by the Bureau of Safety and Environmental Enforcement ("BSEE") arising from Incidents of Noncompliance ("INCs"), which have not been settled as of the filing date of this Form 10-Q. The INC's underlying the civil penalties relate to separate offshore locations with occurrence dates ranging from July 2012 to March 2016. The proposed civil penalties for these INCs total $7.4 million and we are appealing these proposed assessments. During the nine months ended September 30, 2017, we made $0.1 million of payments related to civil penalties. During the nine months ended September 30, 2017, we increased the estimated liability by $1.9 million and have accrued approximately $3.4 million as of September 30, 2017, which is our best estimate of the final settlement once all appeals have been exhausted. Our position is that the proposed civil penalties are excessive given the specific facts and circumstances related to these INCs.

Other Claims. We are a party to various pending or threatened claims and complaints seeking damages or other remedies concerning our commercial operations and other matters in the ordinary course of our business. In addition, claims or contingencies may arise related to matters occurring prior to our acquisition of properties or related to matters occurring subsequent to our sale of properties. In certain cases, we have indemnified the sellers of properties we have acquired, and in other cases, we have indemnified the buyers of properties we have sold. We are also subject to federal and state administrative proceedings conducted in the ordinary course of business including matters related to alleged royalty underpayments on certain federal-owned properties. Although we can give no assurance about the outcome of pending legal and federal or state administrative proceedings and the effect such an outcome may have on us, we believe that any ultimate liability resulting from the outcome of such proceedings, to the extent not otherwise provided for or covered by insurance, will not have a material adverse effect on our consolidated financial position, results of operations or liquidity.

10. Supplemental Guarantor Information

Our payment obligations under the Credit Agreement, the 1.5 Lien Term Loan, the Second Lien Term Loan, the Second Lien PIK Toggle Notes, the Third Lien PIK Toggle Notes and the Unsecured Senior Notes (see Note 2) are fully and unconditionally guaranteed by certain of our 100%-owned subsidiaries, including Energy VI and W & T Energy VII, LLC (together, the "Guarantor Subsidiaries"). W & T Energy VII, LLC does not currently have any active operations or contain any assets. Guarantees will be released under certain circumstances, including:

(1) in connection with any sale or other disposition of all or substantially all of the assets of a Guarantor Subsidiary (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary, if the sale or other disposition does not violate the Asset Sale provisions (as such capitalized terms are defined in the applicable indenture);

(2) in connection with any sale or other disposition of the capital stock of such Guarantor Subsidiary to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the Asset Sale provisions of the indenture and the Guarantor Subsidiary ceases to be a subsidiary of the Company as a result of such sales or disposition;

(3) if such Guarantor Subsidiary is a Restricted Subsidiary and the Company designates such Guarantor Subsidiary as an Unrestricted Subsidiary in accordance with the applicable provisions of certain debt documents;

(4) upon Legal Defeasance or Covenant Defeasance (as such terms are defined in the applicable indenture) or upon satisfaction and discharge of the certain debt documents;

(5) upon the liquidation or dissolution of such Guarantor Subsidiary, provided no event of default has occurred and is continuing; or

(6) at such time as such Guarantor Subsidiary is no longer required to be a Guarantor Subsidiary as described in certain debt documents, provided no event of default has occurred and is continuing.

The following condensed consolidating financial information presents the financial condition, results of operations and cash flows of the Parent Company and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company's results on a consolidated basis. As to the ceiling test write-down recorded in 2016, the computation is performed for each subsidiary on a stand-alone basis and also for the consolidated Company. Due to this methodology, consolidating adjustments are required to present the consolidated results appropriately.

Condensed Consolidating Balance Sheet as of September 30, 2017

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$ 106,164	$ —	$ —	$ 106,164
Receivables:				
Oil and natural gas sales	4,866	34,299	—	39,165
Joint interest	21,877	—	—	21,877
Income taxes	120,402	—	(108,779)	11,623
Total receivables	147,145	34,299	(108,779)	72,665
Prepaid expenses and other assets	13,884	1,189	—	15,073
Total current assets	267,193	35,488	(108,779)	193,902
Oil and natural gas properties and other, net	402,385	156,172	(3,303)	555,254
Restricted deposits for asset retirement obligations	25,339	—	—	25,339
Income tax receivables	52,097	—	—	52,097
Other assets	493,965	441,133	(874,319)	60,779
Total assets	$ 1,240,979	$ 632,793	$ (986,401)	$ 887,371
Liabilities and Shareholders' Equity (Deficit)				
Current liabilities:				
Accounts payable	$ 65,581	$ 6,616	$ —	$ 72,197
Undistributed oil and natural gas proceeds	18,582	1,502	—	20,084
Asset retirement obligations	27,613	1,843	—	29,456
Long-term debt	11,147	—	—	11,147
Accrued liabilities	26,572	108,757	(108,779)	26,550
Total current liabilities	149,495	118,718	(108,779)	159,434
Long-term debt:				
Principal	873,733	—	—	873,733
Carrying value adjustments	108,884	—	—	108,884
Long term debt, less current portion - carrying value	982,617	—	—	982,617
Asset retirement obligations, less current portion	148,468	127,092	—	275,560
Other liabilities	554,366	—	(487,335)	67,031
Shareholders' deficit:				
Common stock	1	—	—	1
Additional paid-in capital	545,422	704,885	(704,885)	545,422
Retained earnings (deficit)	(1,115,223)	(317,902)	314,598	(1,118,527)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity (deficit)	(593,967)	386,983	(390,287)	(597,271)
Total liabilities and shareholders' equity (deficit)	$ 1,240,979	$ 632,793	$ (986,401)	$ 887,371

Condensed Consolidating Balance Sheet as of December 31, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 70,236	$ —	$ —	$ 70,236
Receivables:				
Oil and natural gas sales	2,173	40,900	—	43,073
Joint interest	21,885	—	—	21,885
Insurance reimbursement	30,100	—	—	30,100
Income taxes	111,215	—	(99,272)	11,943
Total receivables	165,373	40,900	(99,272)	107,001
Prepaid expenses and other assets	12,448	2,056	—	14,504
Total current assets	248,057	42,956	(99,272)	191,741
Oil and natural gas properties and other, net	360,966	187,040	(953)	547,053
Restricted deposits for asset retirement obligations	27,371	—	—	27,371
Income tax receivables	52,097	—	—	52,097
Other assets	394,931	344,742	(728,209)	11,464
Total assets	$ 1,083,422	$ 574,738	$ (828,434)	$ 829,726
Liabilities and Shareholders' Deficit				
Current liabilities:				
Accounts payable	$ 74,306	$ 6,733	$ —	$ 81,039
Undistributed oil and natural gas proceeds	24,493	1,761	—	26,254
Asset retirement obligations	62,261	16,003	—	78,264
Long-term debt	8,272	—	—	8,272
Accrued liabilities	9,293	99,179	(99,272)	9,200
Total current liabilities	178,625	123,676	(99,272)	203,029
Long-term debt:				
Principal	873,733	—	—	873,733
Carrying value adjustments	138,722	—	—	138,722
Long term debt, less current portion - carrying value	1,012,455	—	—	1,012,455
Asset retirement obligations, less current portion	142,376	113,798	—	256,174
Other liabilities	408,050	—	(390,945)	17,105
Shareholders' deficit:				
Common stock	1	—	—	1
Additional paid-in capital	539,973	704,885	(704,885)	539,973
Retained earnings (deficit)	(1,173,891)	(367,621)	366,668	(1,174,844)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' deficit	(658,084)	337,264	(338,217)	(659,037)
Total liabilities and shareholders' deficit	$ 1,083,422	$ 574,738	$ (828,434)	$ 829,726

Condensed Consolidating Statement of Operations for the Three Months Ended September 30, 2017

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 51,981	$ 58,300	$ —	$ 110,281
Operating costs and expenses:				
Lease operating expenses	18,796	16,338	—	35,134
Production taxes	340	—	—	340
Gathering and transportation	1,804	2,304	—	4,108
Depreciation, depletion, amortization and accretion	18,804	16,855	830	36,489
General and administrative expenses	7,131	8,500	—	15,631
Derivative gain	2,879	—	—	2,879
Total costs and expenses	49,754	43,997	830	94,581
Operating income	2,227	14,303	(830)	15,700
Earnings of affiliates	13,251	—	(13,251)	—
Interest expense incurred	11,554	—	—	11,554
Gain on exchange of debt	—	—	—	—
Other expense, net	(41)	—	—	(41)
Income before income tax expense	3,965	14,303	(14,081)	4,187
Income tax expense	4,432	1,052	—	5,484
Net income (loss)	$ (467)	$ 13,251	$ (14,081)	$ (1,297)

Condensed Consolidating Statement of Operations for the Nine Months Ended September 30, 2017

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 163,105	$ 194,892	$ —	$ 357,997
Operating costs and expenses:				
Lease operating expenses	59,823	46,994	—	106,817
Production taxes	1,304	—	—	1,304
Gathering and transportation	6,948	8,687	—	15,635
Depreciation, depletion, amortization and accretion	59,391	55,103	2,349	116,843
General and administrative expenses	20,569	24,810	—	45,379
Derivative gain	(4,765)	—	—	(4,765)
Total costs and expenses	143,270	135,594	2,349	281,213
Operating income	19,835	59,298	(2,349)	76,784
Earnings of affiliates	49,719	—	(49,719)	—
Interest expense incurred	34,284	—	—	34,284
Gain on exchange of debt	7,811	—	—	7,811
Other expense, net	5,073	—	—	5,073
Income before income tax expense (benefit)	38,008	59,298	(52,068)	45,238
Income tax expense (benefit)	(20,658)	9,579	—	(11,079)
Net income	$ 58,666	$ 49,719	$ (52,068)	$ 56,317

Condensed Consolidating Statement of Operations for the Three Months Ended September 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 44,585	$ 62,818	$ —	$ 107,403
Operating costs and expenses:				
Lease operating expenses	22,624	14,896	—	37,520
Production taxes	482	—	—	482
Gathering and transportation	2,103	3,058	—	5,161
Depreciation, depletion, amortization and accretion	21,959	29,861	(320)	51,500
Ceiling test write-down of oil and natural gas properties	28,305	25,317	4,290	57,912
General and administrative expenses	5,417	7,275	—	12,692
Derivative loss	412	—	—	412
Total costs and expenses	81,302	80,407	3,970	165,679
Operating loss	(36,717)	(17,589)	(3,970)	(58,276)
Loss of affiliates	(16,925)	—	16,925	—
Interest expense:				
Incurred	23,666	27	—	23,693
Capitalized	(48)	(27)	—	(75)
Gain on exchange of debt	123,960	—	—	123,960
Other expense, net	(73)	—	—	(73)
Loss before income tax benefit	46,773	(17,589)	12,955	42,139
Income tax benefit	(3,125)	(664)	—	(3,789)
Net income (loss)	$ 49,898	$ (16,925)	$ 12,955	$ 45,928

Condensed Consolidating Statement of Operations for the Nine Months Ended September 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 119,011	$ 165,762	$ —	$ 284,773
Operating costs and expenses:				
Lease operating expenses	66,823	51,788	—	118,611
Production taxes	1,378	—	—	1,378
Gathering and transportation	6,125	10,526	—	16,651
Depreciation, depletion, amortization and accretion	65,230	99,956	7,540	172,726
Ceiling test write-down of oil and natural gas properties	28,305	110,709	140,049	279,063
General and administrative expenses	19,390	25,980	—	45,370
Derivative loss	2,861	—	—	2,861
Total costs and expenses	190,112	298,959	147,589	636,660
Operating loss	(71,101)	(133,197)	(147,589)	(351,887)
Loss of affiliates	(130,719)	—	130,719	—
Interest expense:				
Incurred	81,096	184	—	81,280
Capitalized	(336)	(184)	—	(520)
Gain on exchange of debt	123,960	—	—	123,960
Other expense, net	1,209	—	—	1,209
Loss before income tax benefit	(159,829)	(133,197)	(16,870)	(309,896)
Income tax benefit	(41,915)	(2,478)	—	(44,393)
Net loss	$ (117,914)	$ (130,719)	$ (16,870)	$ (265,503)

Condensed Consolidating Statement of Cash Flows for the Nine Months Ended September 30, 2017

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 58,666	$ 49,719	$ (52,068)	$ 56,317
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	59,391	55,103	2,349	116,843
Gain on exchange of debt	(7,811)	—	—	(7,811)
Amortization of debt items	1,271	—	—	1,271
Share-based compensation	5,449	—	—	5,449
Derivative gain	(4,765)	—	—	(4,765)
Cash receipts on derivative settlements, net	3,924	—	—	3,924
Deferred income taxes	321	—	—	321
Earnings of affiliates	(49,719)	—	49,719	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	(2,694)	6,600	—	3,906
Joint interest receivables	8	—	—	8
Insurance reimbursements	31,740	—	—	31,740
Income taxes	(9,259)	9,579	—	320
Prepaid expenses and other assets	1,326	(95,523)	96,391	2,194
Escrow deposit - Apache lawsuit	(49,500)	—	—	(49,500)
Asset retirement obligation settlements	(41,381)	(14,845)	—	(56,226)
Accounts payable, accrued liabilities and other	126,601	(3,881)	(96,391)	26,329
Net cash provided by operating activities	123,568	6,752	—	130,320
Investing activities:				
Investment in oil and natural gas properties and equipment	(68,831)	(10,257)	—	(79,088)
Changes in operating assets and liabilities associated with investing activities	2,174	3,505	—	5,679
Purchases of furniture, fixtures and other	(905)	—	—	(905)
Net cash used in investing activities	(67,562)	(6,752)	—	(74,314)
Financing activities:				
Payment of interest on 1.5 Lien Term Loan	(6,170)	—	—	(6,170)
Payment of interest on 2nd Lien PIK Toggle Notes	(7,335)	—	—	(7,335)
Payment of interest on 3rd Lien PIK Toggle Notes	(6,201)	—	—	(6,201)
Debt exchange costs	(421)	—	—	(421)
Other	49	—	—	49
Net cash used in financing activities	(20,078)	—	—	(20,078)
Increase in cash and cash equivalents	35,928	—	—	35,928
Cash and cash equivalents, beginning of period	70,236	—	—	70,236
Cash and cash equivalents, end of period	$ 106,164	$ —	$ —	$ 106,164

Condensed Consolidating Statement of Cash Flows for the Nine Months Ended September 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net loss	$ (117,914)	$ (130,719)	$ (16,870)	$ (265,503)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	65,230	99,956	7,540	172,726
Ceiling test write-down of oil and natural gas properties	28,305	110,709	140,049	279,063
Gain on exchange of debt	(123,960)	—	—	(123,960)
Debt issuance costs write-off/ amortization of debt items	2,135	—	—	2,135
Share-based compensation	7,642	—	—	7,642
Derivative gain	2,861	—	—	2,861
Cash receipts on derivative settlements	4,746	—	—	4,746
Deferred income taxes	17,962	(2,478)	—	15,484
Loss of affiliates	130,719	—	(130,719)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	4,335	(4,041)	—	294
Joint interest receivables	4,281	—	—	4,281
Income taxes	(52,392)	—	—	(52,392)
Prepaid expenses and other assets	(14,535)	(46,758)	45,165	(16,128)
Asset retirement obligations	(37,925)	(18,242)	—	(56,167)
Accounts payable, accrued liabilities and other	23,584	37,331	(45,165)	15,750
Net cash provided by (used in) operating activities	(54,926)	45,758	—	(9,168)
Investing activities:				
Investment in oil and natural gas properties and equipment	(17,473)	(6,589)	—	(24,062)
Changes in operating assets and liabilities associated with investing activities	2,269	(39,669)	—	(37,400)
Proceeds from sales of assets	1,000	500	—	1,500
Purchases of furniture, fixtures and other	(96)	—	—	(96)
Net cash used in investing activities	(14,300)	(45,758)	—	(60,058)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	340,000	—	—	340,000
Repayments of long-term debt – revolving bank credit facility	(340,000)	—	—	(340,000)
Issuance of 1.5 Lien Term Loan	75,000	—	—	75,000
Debt exchange costs	(17,920)	—	—	(17,920)
Other	83	—	—	83
Net cash provided by financing activities	57,163	—	—	57,163
Decrease in cash and cash equivalents	(12,063)	—	—	(12,063)
Cash and cash equivalents, beginning of period	85,414	—	—	85,414
Cash and cash equivalents, end of period	$ 73,351	$ —	$ —	$ 73,351

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

Forward-Looking Statements

The following discussion and analysis should be read in conjunction with our accompanying unaudited condensed consolidated financial statements and the notes to those financial statements included in Item 1 of this Quarterly Report on Form 10-Q. The following discussion contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). These forward-looking statements involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Known material risks that may affect our financial condition and results of operations are discussed in Item 1A, *Risk Factors,* and market risks are discussed in Item 7A, *Quantitative and Qualitative Disclosures About Market Risk*, of our Annual Report on Form 10-K for the year ended December 31, 2016 and may be discussed or updated from time to time in subsequent reports filed with the SEC. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We assume no obligation, nor do we intend to update these forward-looking statements. Unless the context requires otherwise, references in this Quarterly Report on Form 10-Q to "W&T," "we," "us," "our" and the "Company" refer to W&T Offshore, Inc. and its consolidated subsidiaries and references to "Parent Company" are solely to W&T Offshore, Inc.

Overview

We are an independent oil and natural gas producer, active in the exploration, development and acquisition of oil and natural gas properties in the Gulf of Mexico. We have grown through acquisitions, exploration and development and currently hold working interests in approximately 50 offshore producing fields in federal and state waters. We currently have under lease approximately 710,000 gross acres, with approximately 460,000 gross acres on the shelf and approximately 250,000 gross acres in the deepwater (water depths in excess of 500 feet). A majority of our daily production is derived from wells we operate. Our interest in fields, leases, structures and equipment are primarily owned by the parent company, W&T Offshore, Inc., and our wholly-owned subsidiary, W & T Energy VI, LLC.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for the nine months ended September 30, 2017 were comprised of 48.8% oil and condensate, 9.2% NGLs and 42.0% natural gas, determined using the energy equivalency ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price per one Boe for oil, NGLs and natural gas has differed significantly in the past. For the nine months ended September 30, 2017, revenues from the sale of oil and NGLs made up 75.7% of our total revenues compared to 74.6% for the same period in 2016. For the nine months ended September 30, 2017, our combined total production was 4.6% lower than the same period in 2016, with NGLs having the largest decline. For the nine months ended September 30, 2017, our total revenues were 25.7% higher than the same period in 2016 due primarily to significantly higher realized prices for all three of our commodities - oil, NGLs and natural gas. See *Results of Operations – Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016* in this Item for additional information.

On September 7, 2016, we consummated a transaction whereby we exchanged approximately $710.2 million in aggregate principal amount, or 79%, of our Unsecured Senior Notes due 2019 for new secured notes and common stock. At the same time, we closed on a new $75.0 million, 1.5 Lien Term Loan. See *Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q and *Liquidity and Capital Resources* in this Item for additional information.

Our operating results are strongly influenced by the price of the commodities that we produce and sell. The price of those commodities is affected by both domestic and international factors, including domestic production. During the nine months ended September 30, 2017, our average realized oil price was $45.81 per barrel. This is an increase over our average realized oil price of $35.01 per barrel for the nine months ended September 30, 2016 and an increase over our average realized oil price of $37.35 per barrel for the year 2016. In addition, average realized prices of NGLs and natural gas for the nine months ended September 30, 2017 were higher than average realized prices for the nine months ended September 30, 2016 and the year 2016.

The overall crude oil and other petroleum liquids market has shifted to a less oversupplied position for the nine months ended September 30, 2017 compared to a significant oversupplied position for the same period last year. While this contributed to higher prices and reduced inventories in 2017, the current high inventory levels compared to historical levels have continued to exert downward pressure on prices. This in turn has prevented any significant price improvement. The market has shifted to backwardation (current prices higher than future prices) starting in the March and April 2018 time frame with prices decreasing thereafter for many quarters in the future. In addition, as described below, inventories are expected to rise in 2018, which may put additional downward pressure on prices.

Selected issues and data points related to crude oil, NGLs and natural gas markets are described below.

The U.S. Energy Information Administration ("EIA") reported worldwide crude oil and petroleum liquids inventory decreases in each of the first three quarters of 2017, the longest such stretch since the 2013-2014 timeframe. For the year 2017, the EIA revised its estimates of worldwide crude oil and petroleum liquids demand and now estimates full 2017 demand to be higher than supply, where the previous forecast had the market close to parity. EIA forecasts crude oil and other petroleum liquids inventories to decrease 0.3 million barrels per day for 2017. EIA expects worldwide petroleum production to increase by 0.8 million barrels per day in 2017 over 2016 and increase by 2.1 million barrels per day in 2018 over 2017. The expected increases are primarily in the U.S. and the Organization of the Petroleum Exporting Countries ("OPEC") for both years. China and Mexico are expected to experience petroleum liquid production declines in 2017. Petroleum liquid consumption is forecast to increase by 1.4 million barrels per day in 2017 over 2016, and further increase by 1.6 million barrels per day in 2018 over 2017. Economic conditions are expected to strengthen globally as measured by the Purchasing Managers' Indexes among the countries measured. China and the U.S. are expected to be the largest contributors to the increased petroleum liquids demand for 2017 and 2018, although increases are forecasted for almost every country or groups of countries reported by EIA.

According to data provided by EIA, the estimate for 2017 of U.S. crude oil production (excluding other petroleum liquids) is an increase of 4% from 2016 and a further increase by 7% in 2018 over 2017. If EIA's forecast is achieved in 2018, oil production in the U.S will be at the highest level in recorded history, surpassing the current record set in 1970. As noted below, the number of rigs drilling for oil has more than doubled compared to a year ago.

In addition, it is important to note that geopolitical events could greatly affect the prices for oil, natural gas and other petroleum products. While these events are difficult to predict, we note the deteriorating political environment in Venezuela could affect approximately 0.7 million barrels per day of crude oil exports to the U.S. In Libya, the civil unrest at one of its largest oil fields presents uncertainty about future production and Turkey has threatened to disrupt the pipeline flows of oil produced in the Kurdistan region of Iraq due to a vote for independence, as Turkey sided with Iraq's central government. In addition, the political environments in other international areas, such as other Middle East countries, Nigeria and North Korea, could also affect prices for oil, natural gas and other petroleum products.

During the nine months ended September 30, 2017, our average realized oil sales price was $45.81, up from $35.01 per barrel (30.8% higher) for the same period in 2016. The two primary benchmarks are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $49.30 per barrel for the nine months ended September 30, 2017, up from $41.35 per barrel (19.2% higher) for the same period in 2016. Brent crude oil prices averaged $51.57 per barrel for the nine months ended September 30, 2017, up from $45.80 per barrel (13.0% higher) for the same period in 2016. The reductions in international crude oil supply and rising U.S. crude oil production put upward price pressure on the premium of Brent to WTI, as the Brent-to-WTI premium increased in the nine months ended September 30, 2017 compared to the same period in 2016.

Our average realized oil sales price ($45.81 per barrel compared to a WTI benchmark price of $49.30 perbarrel) for the nine months ended September 30, 2017 differs from the benchmark crude prices due to premiums or discounts (referred to as differentials), crude quality adjustments, volume weighting and other factors. All of our oil was produced offshore in the Gulf of Mexico and is characterized as Poseidon, Light Louisiana Sweet ("LLS"), Heavy Louisiana Sweet ("HLS") and others. WTI is frequently used to value domestically produced crude oil, and the majority of our oil production is priced using the spot price for WTI as a base price, then adjusted for the type and quality of crude oil and other factors. Similar to crude oil prices, the differentials for our offshore crude oil have also experienced volatility in the past. The monthly average differentials of WTI versus Poseidon, LLS and HLS for the nine months ended September 30, 2017 were a negative $1.88, a positive $1.97 and a positive $1.59 per barrel, respectively, compared to a negative $3.58, a positive $1.79 and a positive $0.87 per barrel, respectively, for the same period in 2016. The majority of our crude oil is priced similar to Poseidon and therefore, is experiencing negative differentials. In addition, a few of our crude oil fields have a negative quality bank adjustment.

EIA projects average crude oil prices for WTI and Brent to increase by approximately $6.00 per barrel and $9.00 per barrel, respectively, for the year 2017 compared to 2016. EIA's forecast of crude oil prices for WTI and Brent are expected to increase by approximately $1.00 per barrel and $2.00 per barrel, respectively, for the year 2018 compared to 2017. Per EIA, uncertainty remains regarding the duration of, and adherence to, the current OPEC production cuts, which could influence prices in either direction. Also, the U.S. tight oil sector continues to be dynamic, and quickly evolving trends in this sector could affect both current prices and the expectations for future prices. However, lasting upward and downward price movements could be limited over the next year because a substantial majority of U.S. producers have locked in their prices with financial commodity derivatives allowing them to continue to drill and produce even if prices fall. In addition, the strength in the U.S. dollar relative to other currencies also has an impact on crude pricing. Because all barrels are traded in U.S. dollars, as the U.S. dollar gains strength, crude prices are lower in U.S. dollars but are more expensive in other currencies.

During the nine months ended September 30, 2017, our average realized NGLs sales price increased 38.0% compared to the same period in 2016. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the nine months ended September 30, 2017, average prices for domestic ethane increased 28% and average domestic propane prices increased 56% from the same period in 2016. Average price changes for other domestic NGLs were an increase of 21% to 49% between the two periods. We believe the increase in prices for NGLs is mostly a function of the change in oil and natural gas prices. Per EIA, production of ethane is expected to increase 11% for 2017 compared to 2016 and propane production is expected to increase by 3% for 2017 compared to 2016. Ethane production was at parity to demand in the third quarter of 2017, leading to stable inventory levels compared to the second quarter of 2017. Compared to the same period in 2016, ethane inventories increased 7%. Many natural gas processing facilities have been and, from time to time, will likely continue re-injecting ethane back into the natural gas stream after processing until there is sufficient ethane demand. This practice of re-injecting ethane negatively impacts natural gas prices. Ethane usage is not impacted by weather, but primarily by demand from petrochemical plants. Ethane demand is expected to increase in 2017 over 2016 as two new petrochemical plants came on line in the first half of 2017 and five more are expected to be operational by the end of 2018. On the other hand, propane usage is affected by weather as it is used for house heating fuel in certain areas and for crop drying, along with other uses. Propane inventory levels are 24% lower at the end of the third quarter of 2017 compared to the same period last year.

During the nine months ended September 30, 2017, our average realized natural gas sales price increased 27.5 % compared to the same period in 2016. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 27.4% higher in the nine months ended September 30, 2017 compared to the same period in 2016. Natural gas prices are more affected by domestic issues (as compared to crude oil prices), such as weather (particularly extreme heat or cold), supply, local demand issues, other fuel competition (coal) and domestic economic conditions, and they have historically been subject to substantial fluctuation. Natural gas average spot prices for the third quarter of 2017 were 4% lower than the second quarter of 2017. Hurricane Irma reduced demand in Florida, where most electricity generation is fueled by natural gas. Natural gas inventories at the end of the third quarter of 2017 were 4% lower than the prior year period, but were 2% above the five-year average.

The average price of natural gas continues to be weak from an overall economic standpoint, and we expect continued weakness in natural gas prices for a number of reasons, including (i) producers continuing to drill in order to secure and to hold large lease positions before expiration, particularly in shale and similar resource plays, (ii) natural gas continuing to be produced as a by-product of oil drilling, (iii) production efficiency gains being achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling, pad drilling and production techniques, (iv) higher inventory levels and (v) re-injecting ethane into the natural gas stream as indicated above, which increases the natural gas supply.

EIA projects natural gas prices to increase in 2017 compared to 2016 by 20% and to increase 5% in 2018 compared to 2017. U.S. supply is projected to be slightly less than consumption in 2017 and 2018, resulting in minor inventory drawdowns. As a result, excess inventory is not expected to be significantly changed, which limits any significant upward price movement. During 2016, natural gas overtook coal as being the largest fuel source for electrical power generation, supplying 34% of the megawatts generated compared to 30% from coal. EIA's forecast of fuel used for electrical power generation has natural gas declining in 2017 to 31% and being approximately equal with coal. Electrical power from renewable sources such as hydropower and wind is expected to increase in 2017 to 17% compared to 15% in 2016. For 2018, electrical power from natural gas is expected to increase to 32%, with coal and renewable sources being relatively unchanged from 2017 levels.

During the nine months ended September 30, 2017, the number of working rigs drilling for oil and natural gas in the U.S. was significantly higher than year ago levels for land based rigs, but only higher by one rig for offshore rigs. According to Baker Hughes, the oil rig count at September 2016, December 2016 and September 2017 was 425, 525 and 750 (a 76% increase from year ago levels), respectively. The U.S. natural gas rig count at September 2016, December 2016 and September 2017 was 96, 132 and 189, respectively. In the Gulf of Mexico, the number of working rigs was 21 rigs (20 oil and one natural gas) at September 2016; 22 rigs (22 oil and no natural gas) at December 2016; and 22 rigs (18 oil and four natural gas) at September 30 2017. The majority of working rigs in the Gulf of Mexico are currently "floaters" with very few jack-up rigs working.

As required by the full cost accounting rules, we perform our ceiling test calculation each quarter using the SEC pricing guidelines, which require using the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price adjusted for price differentials. Incurrence of write downs is dependent primarily on the price of crude oil and natural gas, but also is affected by quantities of proved reserves, future development costs and future lease operating costs. Using prices, reserve balances and other information available as of the filing date of this Form 10-Q, we do not anticipate a ceiling test write down in the fourth quarter of 2017.

Our current 2017 capital expenditure budget remains unchanged at $125.0 million, which is above the capital expenditures incurred in 2016 of $48.6 million, but reduced from investment levels in 2015 and 2014 of $231.4 million and $630.0 million, respectively. Assuming current commodity price and cost levels, we expect to have adequate cash balances and no draws on our revolving bank credit facility for the remainder of 2017. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments.

With respect to our costs, we have realized reductions in our lease operating expenses and general and administrative expenses as a result of our cost reduction programs, which included headcount and contractor usage reductions, combined with reduced rates from vendors for supplies, equipment and contract labor. These cost reduction programs and reduced supplier rates have also lowered capital expenditures, ARO settlements and ARO estimates.

Our short term focus is on liquidity, cost reductions, fulfilling our obligations and making investments with short payback time frames. In light of our somewhat limited access to capital and liquidity, we are continually assessing our plans. We continue to closely monitor current and forecasted prices to assess if changes are needed to our plans. See our Annual Report on Form 10-K for the year ended December 31, 2016, Item 1A, *Risk Factors,* for additional information.

Results of Operations

The following tables set forth selected financial and operating data for the periods indicated (all values are net to our interest unless indicated otherwise):

	Three Months Ended September 30, 2017	2016	Change	%	Nine Months Ended September 30, 2017	2016	Change	%
	(In thousands, except percentages and per share data)							
Financial:								
Revenues:								
Oil	$ 78,055	$ 70,974	$ 7,081	10.0%	$ 248,648	$ 193,661	$ 54,987	28.4%
NGLs	6,605	6,696	(91)	(1.4)%	22,401	18,709	3,692	19.7%
Natural gas	24,113	29,135	(5,022)	(17.2)%	83,129	69,238	13,891	20.1%
Other	1,508	598	910	152.2%	3,819	3,165	654	20.7%
Total revenues	110,281	107,403	2,878	2.7%	357,997	284,773	73,224	25.7%
Operating costs and expenses:								
Lease operating expenses	35,134	37,520	(2,386)	(6.4)%	106,817	118,611	(11,794)	(9.9)%
Production taxes	340	482	(142)	(29.5)%	1,304	1,378	(74)	(5.4)%
Gathering and transportation	4,108	5,161	(1,053)	(20.4)%	15,635	16,651	(1,016)	(6.1)%
Depreciation, depletion, amortization and accretion	36,489	51,500	(15,011)	(29.1)%	116,843	172,726	(55,883)	(32.4)%
Ceiling test write-down of oil and natural gas properties	—	57,912	(57,912)	NM	—	279,063	(279,063)	NM
General and administrative expenses	15,631	12,692	2,939	23.2%	45,379	45,370	9	0.0%
Derivative (gain) loss	2,879	412	2,467	NM	(4,765)	2,861	(7,626)	NM
Total costs and expenses	94,581	165,679	(71,098)	(42.9)%	281,213	636,660	(355,447)	(55.8)%
Operating income (loss)	15,700	(58,276)	73,976	NM	76,784	(351,887)	428,671	NM
Interest expense, net of amounts capitalized	11,554	23,618	(12,064)	(51.1)%	34,284	80,760	(46,476)	(57.5)%
Gain on exchange of debt	—	123,960	(123,960)	NM	7,811	123,960	(116,149)	NM
Other (income) expense, net	(41)	(73)	32	NM	5,073	1,209	3,864	NM
Income (loss) before income tax expense (benefit)	4,187	42,139	(37,952)	(90.1)%	45,238	(309,896)	355,134	NM
Income tax expense (benefit)	5,484	(3,789)	9,273	NM	(11,079)	(44,393)	33,314	(75.0)%
Net income (loss)	$ (1,297)	$ 45,928	$ (47,225)	NM	$ 56,317	$ (265,503)	$ 321,820	NM
Basic and diluted earnings (loss) per common share	$ (0.01)	$ 0.48	$ (0.49)	NM	$ 0.39	$ (3.25)	$ 3.64	NM

NM – not meaningful

	Three Months Ended September 30, 2017	2016	Change	% (2)	Nine Months Ended September 30, 2017	2016	Change	% (2)
Operating: (1)								
Net sales:								
Oil (MBbls)	1,700	1,791	(91)	(5.1)%	5,428	5,532	(104)	(1.9)%
NGLs (MBbls)	299	372	(73)	(19.6)%	1,024	1,180	(156)	(13.2)%
Natural gas (MMcf)	8,130	9,935	(1,805)	(18.2)%	28,005	29,696	(1,691)	(5.7)%
Total oil equivalent (MBoe)	3,354	3,819	(465)	(12.2)%	11,119	11,661	(542)	(4.6)%
Total natural gas equivalents (MMcfe)	20,125	22,912	(2,787)	(12.2)%	66,714	69,967	(3,253)	(4.6)%
Average daily equivalent sales (Boe/day)	36,459	41,508	(5,049)	(12.2)%	40,729	42,559	(1,830)	(4.3)%
Average daily equivalent sales (Mcfe/day)	218,752	249,045	(30,293)	(12.2)%	244,372	255,355	(10,983)	(4.3)%
Average realized sales prices:								
Oil ($/Bbl)	$ 45.92	$ 39.62	$ 6.30	15.9%	$ 45.81	$ 35.01	$ 10.80	30.8%
NGLs ($/Bbl)	22.07	18.02	4.05	22.5%	21.88	15.85	6.03	38.0%
Natural gas ($/Mcf)	2.97	2.93	0.04	1.4%	2.97	2.33	0.64	27.5%
Oil equivalent ($/Boe)	32.43	27.97	4.46	15.9%	31.85	24.15	7.70	32.0%
Natural gas equivalent ($/Mcfe)	5.40	4.66	0.74	15.9%	5.31	4.02	1.29	32.0%
Average per Boe ($/Boe):								
Lease operating expenses	$ 10.48	$ 9.82	$ 0.66	6.7%	$ 9.61	$ 10.17	$ (0.56)	(5.5)%
Gathering and transportation	1.22	1.35	(0.13)	(9.6)%	1.41	1.43	(0.02)	(1.4)%
Production costs	11.70	11.17	0.53	4.7%	11.02	11.60	(0.58)	(5.0)%
Production taxes	0.10	0.13	(0.03)	(23.1)%	0.12	0.12	—	—
DD&A	10.88	13.49	(2.61)	(19.3)%	10.51	14.81	(4.30)	(29.0)%
General and administrative expenses	4.66	3.32	1.34	40.4%	4.08	3.89	0.19	4.9%
	$ 27.34	$ 28.11	$ (0.77)	(2.7)%	$ 25.73	$ 30.42	$ (4.69)	(15.4)%
Average per Mcfe ($/Mcfe):								
Lease operating expenses	$ 1.75	$ 1.64	$ 0.11	6.7%	$ 1.60	$ 1.70	$ (0.10)	(5.9)%
Gathering and transportation	0.20	0.23	(0.03)	(13.0)%	0.23	0.24	(0.01)	(4.2)%
Production costs	1.95	1.87	0.08	4.3%	1.83	1.94	(0.11)	(5.7)%
Production taxes	0.02	0.02	—	—	0.02	0.02	—	—
DD&A	1.81	2.25	(0.44)	(19.6)%	1.75	2.47	(0.72)	(29.1)%
General and administrative expenses	0.78	0.55	0.23	41.8%	0.68	0.65	0.03	4.6%
	$ 4.56	$ 4.69	$ (0.13)	(2.8)%	$ 4.28	$ 5.08	$ (0.80)	(15.7)%

(1) The conversions to barrels of oil equivalent and cubic feet equivalent were determined using the energy equivalency ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price on an equivalent basis for oil, NGLs and natural gas may differ significantly.

(2) Variance percentages are calculated using rounded figures and may result in different figures for comparable data.

Volume measurements:

Bbl - barrel
Boe - barrel of oil equivalent
MBbls - thousand barrels for crude oil, condensate or NGLs
MBoe - thousand barrels of oil equivalent
Mcf - thousand cubic feet
Mcfe - thousand cubic feet equivalent
MMcf - million cubic feet
MMcfe - million cubic feet equivalent

Three Months Ended September 30, 2017 Compared to the Three Months Ended September 30,2016

Revenues. Total revenues increased $2.9 million, or 2.7%, to $110.3 million for the third quarter of 2017 as compared to the third quarter of 2016. Oil revenues increased $7.1 million, or 10.0%, NGLs revenues decreased $0.1 million, or 1.4%, natural gas revenues decreased $5.0 million, or 17.2%, and other revenues increased $0.9 million. The increase in oil revenues was attributable to a 15.9% increase in the average realized sales price to $45.92 per barrel for the third quarter of 2017 from $39.62 per barrel for the third quarter of 2016, partially offset by a decrease of sales volumes of 5.1%. NGLs revenues were relatively flat, with decreases in sales volumes being offset by an increase in the average realized sales price. The decrease in natural gas revenues was attributable to lower sales volumes of 18.2%. This was partially offset by an increase in the average realized price to $2.97 per Mcf for the third quarter of 2017 from $2.93 per Mcf for the third quarter of 2016. Overall, production volume decreased 12.2% on a Boe basis. The largest production increases for the third quarter of 2017 compared to the third quarter of 2016 were at the Ship Shoal 349 ("Mahogany"), Ewing Bank 910 and the Viosco Knoll 823 ("Virgo") fields. Offsetting were production decreases primarily due to natural production declines. In addition, production for the third quarter of 2017 was impacted by well maintenance, weather, pipeline outages and platform maintenance that collectively resulted in deferred production of almost 4,900 Boe per day.

Revenues from oil and liquids as a percent of our total revenues were 76.8% for the third quarter of 2017 compared to 72.3% for the third quarter of 2016. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 48.1% for the third quarter of 2017 compared to 45.5% for the third quarter of 2016.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $2.4 million, or 6.4%, to $35.1 million in the third quarter 2017 compared to the third quarter of 2016. On a component basis, base lease operating expenses decreased $4.0 million and workover expenses decreased $1.2 million, partially offset by increased facilities maintenance expense of $2.2 million and increased insurance premiums of $0.6 million. Base lease operating expenses decreased primarily due to continued cost reduction efforts by the Company, cost reductions at non-operated properties and from lower processing costs at one of our fields. The decrease in workover expense was primarily due to reclassifying such costs to a capital project because a workover project turned into a sidetrack well. The facility maintenance expense increase is primarily due to engine and compressor overhauls and maintenance at several platforms. Insurance premium increases are primarily due to revisions in our insurance policies related to named windstorms.

Production taxes. Production taxes decreased $0.1 million for the third quarter of 2017 compared to the third quarter of 2016. Most of our production is from federal waters where no production taxes are imposed. Our Fairway field, which is in state waters, is subject to production taxes.

Gathering and transportation. Gathering and transportation expenses decreased $1.1 million to $4.1 million for the third quarter of 2017 compared to the third quarter of 2016 primarily due to lower production volumes of NGLs and natural gas.

Depreciation, depletion, amortization and accretion ("DD&A"). DD&A, which includes accretion for ARO, decreased to $10.88 per Boe for the third quarter of 2017 from $13.49 per Boe for the third quarter of 2016. On a nominal basis, DD&A decreased to $36.5 million (29.1%) for the third quarter of 2017 from $51.5 million for the third quarter of 2016. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2016 and lower capital expenditures in relation to DD&A expense during 2016, both of which lowers the full-cost pool subject to DD&A. Other factors affecting the DD&A rate are changes in future development costs on remaining reserves and changes in proved reserves.

Ceiling test write-down of oil and natural gas properties. For the third quarter of 2017, we did not have a ceiling test write-down of the carrying value of our oil and gas properties. For the third quarter of 2016, we recorded a non-cash ceiling test write-down of $57.9 million as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down was primarily the result of lower prices on all commodities for our proved reserves. See our Annual Report on Form 10-K for the year ended December 31, 2016, Item 8, *Financial Statements and Supplementary Data* for additional information on the ceiling test.

General and administrative expenses ("G&A"). G&A was $15.6 million for the third quarter of 2017, up 23.2% from $12.7 million for the third quarter of 2016. Increases in incentive compensation in 2017 and the effect of reinstating the Company's 401K match program were partially offset by reductions in salary expense and share-based compensation. During the third quarter of 2017, we accrued expenses related to our short-term incentive compensation program as we estimate achieving some of the pre-defined performance measures for the full year of 2017. In the third quarter of 2016, no accruals were made for the short-term incentive compensation program. In addition, during the third quarter of 2016, transaction costs related to the Exchange Transaction previously recorded as G&A expenses were reclassified to *Gain on Exchange of Debt* described below. G&A on a per Boe basis was $4.66 per Boe for the third quarter of 2017 compared to $3.32 per Boe for the third quarter of 2016.

Derivative (gain) loss. The third quarter of 2017 reflects a $2.9 million derivative loss for our crude oil and natural gas derivative contracts, which includes settled contracts and open contracts recorded at fair value as of September 30, 2017. We entered into derivative contracts for crude oil and natural gas during the first quarter of 2017 relating to a portion of our 2017 estimated production. The third quarter of 2016 reflects a $0.4 million derivative loss for our crude oil and natural gas derivative contracts.

Interest expense. Interest expense, net of amounts capitalized, was $11.6 million in the third quarter of 2017, decreasing 51.1% from $23.6 million for the third quarter of 2016. The decrease was primarily attributable to the Exchange Transaction that was completed on September 7, 2016, when we exchanged $710.2 million of our Unsecured Senior Notes for $301.8 million of new secured notes and 60.4 million shares of common stock, and at the same time, closed on a $75.0 million, 1.5 Lien Term Loan. In addition, interest expense was lower as we had no borrowings on the revolving bank credit facility during the third quarter of 2017 compared to borrowings averaging over $100 million during the third quarter of 2016. *See Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information.

Gain on exchange of debt. During the third quarter of 2016, a net gain of $124.0 million was recognized related to the Exchange Transaction. Under ASC 470-60, a gain was recognized as undiscounted future cash flows of the debt issued in the Exchange Transaction, plus the fair value of the common stock issued and deal transaction costs were less than the sum of the carrying value of the Unsecured Senior Notes exchanged combined with the funds received from the 1.5 Lien Term Loan issued. *See Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information.

Income tax expense (benefit). Our income tax expense for the third quarter of 2017 was $5.5 million and our income tax benefit for the third quarter of 2016 was $3.8 million. Under GAAP, we are required to use the annualized effective tax rate method in computing income tax expense or benefit for interim periods. Somewhat improving commodity prices and a relatively lower forecasted spend for plug and abandonment work in 2017 revised our forecast, which required us to reduce the amount of benefits previously recorded in the first half of 2017 under the annualized effective tax rate method. Based on current information, we expect our tax benefit for the 2017 fiscal year to be around $14 million. The full year estimated benefit relates to NOL carryback claims made pursuant to IRC Section 172(f) (related to rules for "specified liability losses"), which permit certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. The income tax benefit for the third quarter of 2016 was also primarily due to NOL carryback claims under IRC Section 172(f). Our effective tax rate using book pre-tax income was not meaningful for either period. For both periods, adjustments in the valuation allowance offset changes in net deferred tax assets. See *Financial Statements – Note 7 –Income Taxes* under Part I, Item 1 of this Form 10-Q for additional information.

Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016

Revenues. Total revenues increased $73.2 million, or 25.7%, to $358.0 million for the nine months ended September 30, 2017 as compared to the same period in 2016. Oil revenues increased $55.0 million, or 28.4%, NGLs revenues increased $3.7 million, or 19.7%, natural gas revenues increased $13.9 million, or 20.1%, and other revenues increased $0.7 million. The increase in oil revenues was attributable to a 30.8% increase in the average realized sales price to $45.81 per barrel for the nine months ended September 30, 2017 from $35.01 per barrel for the same period in 2016, partially offset by a 1.9% decrease in sales volumes. The increase in NGLs revenues was attributable to a 38.0% increase in the average realized sales price to $21.88 per barrel for the nine months ended September 30, 2017 from $15.85 per barrel for the same period in 2016, partially offset by a 13.2% decrease in sales volumes. The increase in natural gas revenues resulted from a 27.5% increase in the average realized natural gas sales price to $2.97 per Mcf for the nine months ended September 30, 2017 from $2.33 per Mcf for the same period in 2016, partially offset by a 5.7% decrease in sales volumes. Overall, production declined 4.6% on an MBoe basis. The largest production increases for the nine months ended September 30, 2017 compared to the same period in 2016 were at the Mahogany, Ewing Bank 910, Viosco Knoll 823 ("Virgo"), Garden Banks 302 ("Powerplay"), Main Pass 108 and East Cameron 321 fields. In addition, we received royalty relief for a portion of 2016 crude oil royalties and all 2016 natural gas royalties related to the Mississippi Canyon 698 ("Big Bend") and Mississippi Canyon 782 ("Dantzler") fields, which increased revenues by $5.0 million and sales volumes by approximately 175,000 MBoe. Offsetting were production decreases primarily due to natural production declines.

Revenues from oil and liquids as a percent of our total revenues were 75.7% for the nine months ended September 30, 2017 compared to 74.6% for the same period in 2016. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 47.8% for the nine months ended September 30, 2017 compared to 45.3% for the same period in 2016.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $11.8 million, or 9.9%, to $106.8 million in the nine months ended September 30, 2017 compared to the same period in 2016. On a per Boe basis, lease operating expenses decreased to $9.61 per Boe during the nine months ended September 30, 2017 compared to $10.17 per Boe during the same period in 2016. On a component basis, base lease operating expenses decreased $12.6 million and insurance premiums decreased $3.0 million, partially offset by increases in workover expenses of $2.3 million and increases in facilities maintenance expenses of $1.5 million. Base lease operating expenses decreased primarily due to continued cost reduction efforts by the Company, cost reductions at non-operated properties and from lower processing costs at one of our fields. Insurance premium reductions are primarily due to revisions in our insurance policies related to named windstorms. The increase in workover costs was primarily due to increases for well work at the Mahogany field. The increase in facilities maintenance expense was primarily due to a complete engine and compressor overhaul at Matterhorn.

Production taxes. Production taxes decreased less than $0.1 million for the nine months ended September 30, 2017 compared to the same period in 2016. Most of our production is from federal waters where no production taxes are imposed. Our Fairway field, which is in state waters, is subject to production taxes.

Gathering and transportation. Gathering and transportation expenses decreased $1.0 million for the nine months ended September 30, 2017 compared to the same period in 2016 primarily due to lower production volumes of NGLs and natural gas.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, decreased to $10.51 per Boe for the nine months ended September 30, 2017 from $14.81 per Boe for the same period in 2016. On a nominal basis, DD&A decreased to $116.8 million (32.4%) for the nine months ended September 30, 2017 from $172.7 million for the same period in 2016. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2016 and lower capital expenditures in relation to DD&A expense during 2016, both of which lowers the full-cost pool subject to DD&A. Other factors affecting the DD&A rate are changes in future development costs on remaining reserves and changes in proved reserves.

Ceiling test write-down of oil and natural gas properties. For the nine months ended September 30, 2017, we did not have a ceiling test write-down of the carrying value of our oil and gas properties. For the same period in 2016, we recorded a non-cash ceiling test write-down of $279.1 million as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down was primarily the result of lower prices on all commodities for our proved reserves. See our Annual Report on Form 10-K for the year ended December 31, 2016, Item 8, *Financial Statements and Supplementary Data* for additional information on the ceiling test.

General and administrative expenses. For the nine months ended September 30, 2017 and September 30, 2016, G&A was $45.4 million for both periods. During the nine months ended September 30, 2017, we experienced reductions in salary expense, legal expense, benefits costs and information technology costs, offset by increases in incentive compensation, accrued civil penalties from the BSEE (which we are appealing to the IBLA) and surety bond costs. G&A on a per BOE basis was $4.08 per Boe for the nine months ended September 30, 2017 compared to $3.89 per Boe for the same period in 2016.

Derivative (gain) loss. For the nine months ended September 30, 2017, a $4.8 million derivative gain was recorded for crude oil and natural gas derivative contracts, which includes settled contracts and open contracts recorded at fair value as of September 30, 2017. We entered into derivative contracts for crude oil and natural gas during the first quarter of 2017 relating to a portion of our 2017 estimated production. For the same period in 2016, a $2.9 million derivative loss was recorded for our crude oil and natural gas derivative contracts.

Interest expense. Interest expense, net of amounts capitalized, was $34.3 million in the nine months ended September 30, 2017, decreasing 57.5% from the $80.8 million for the same period in 2016. The decrease was primarily attributable to the Exchange Transaction that was completed on September 7, 2016, when we exchanged $710.2 million of our Unsecured Senior Notes for $301.8 million of new secured notes and 60.4 million shares of common stock, and at the same time, closed on a $75.0 million, 1.5 Lien Term Loan. In addition, interest expense was lower as we had no borrowings on the revolving bank credit facility during the nine months ended September 30, 2017 compared to borrowings averaging approximately $150.0 million during the same period in 2016. *See Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information.

Gain on exchange of debt. During the nine months ended September 30, 2017, an additional net gain of $7.8 million was recognized primarily as a result of paying interest in cash on the Second Lien PIK Toggles Notes and the Third Lien PIK Toggle Notes versus paying the interest in kind. The cash interest payments on Second Lien PIK Toggles Notes and the Third Lien PIK Toggle Notes lowered the carrying value of the respective notes under ACS 470-60, resulting in the recognition of a non-cash gain. The cash payments have a lower interest rate compared to the PIK option and this also reduced future interest and principal payments. Partially offsetting were additional expenses related to the Exchange Transaction for differences between estimated and actual expense. During the third quarter of 2016, a net gain of $124.0 million was recognized related to the Exchange Transaction. Under ASC 470-60, a gain was recognized as undiscounted future cash flows of the debt issued in the Exchange Transaction, plus the fair value of the common stock issued and deal transaction costs were less than the sum of the carrying value of the Unsecured Senior Notes exchanged combined with the funds received from the 1.5 Lien Term Loan issued. *See Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information.

Other (income) expense, net. During the nine months ended September 30, 2017 and 2016, other (income) expense, net, was $5.1 million of net expense and $1.2 million of net expense, respectively. For the nine months ended September 30, 2017, the amount consists primarily of expense items related to the Apache lawsuit of $6.3 million, partially offset by loss-of-use reimbursements from a third-party for damages incurred at one of our platforms of $1.1 million. *See Financial Statements - Note 9 – Contingencies* under Part I, Item 1 of this Form 10-Q for additional information on the Apache lawsuit. For the nine months ended September 30, 2016, the amount was primarily due to the write-down of debt issuance costs related to a reduction in the borrowing base of our revolving bank credit facility.

Income tax benefit. Our income tax benefit for the nine months ended September 30, 2017 and 2016 was $11.1 million and $44.4 million, respectively. Under GAAP, we are required to use the annualized effective tax rate method in computing income tax expense or benefit for interim periods. Somewhat improving commodity prices and a relatively lower forecasted spend for plug and abandonment work in 2017 revised our forecast, which required us to reduce the amount of benefits previously recorded in the first half of 2017 under the annualized effective tax rate method. Based on current information, we expect our tax benefit for the 2017 fiscal year to be around $14 million. The income tax benefit for both periods relates to NOL carryback claims made pursuant to IRC Section 172(f) (related to rules for "specified liability losses"), which permit certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. Our effective tax rate using book pre-tax income was not meaningful for either period. For both periods, adjustments in the valuation allowance offset changes in net deferred tax assets. See *Financial Statements – Note 7 –Income Taxes* under Part I, Item 1 of this Form 10-Q for additional information.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures and strategic property acquisitions to allow us to replace our oil and natural gas reserves, repay outstanding borrowings, make related interest payments and satisfy our asset retirement obligations. We have funded such activities in the past with cash on hand, net cash provided by operating activities, sales of property, securities offerings and bank borrowings.

If commodity prices were to return to the weaker levels seen in the early part of 2016, especially relative to our cost of finding and producing new reserves, this could have a significant adverse effect on our liquidity. In addition, other events outside of our control could significantly affect our liquidity such as demands for additional financial assurances from the BOEM. If such events were to occur in the future, we may seek relief under the U.S. Bankruptcy Code, which relief may include (i) seeking bankruptcy court approval for the sale or sales of some, most or substantially all of our assets and a subsequent liquidation of the remaining assets in the bankruptcy case; (ii) pursuing a plan of reorganization or (iii) seeking another form of bankruptcy relief, all of which involve uncertainties, potential delays and litigation risks.

Additionally, a prolonged period of weak commodity prices could have other potential negative impacts including:

- recognizing additional ceiling test write-downs of the carrying value of our oil and gas properties;
- reductions in our proved reserves and the estimated value thereof;
- additional supplemental bonding and potential collateral requirements;
- further reductions in our borrowing base under the Credit Agreement; and
- our ability to fund capital expenditures needed to replace produced reserves, which must be replaced on a long-term basis to provide cash to fund liquidity needs described above.

During 2016, we engaged legal and financial advisors to assist the Board of Directors and our management team to evaluate the various alternatives available to us. On September 7, 2016, we consummated the Exchange Transaction, which significantly changed our debt and equity structure. See *Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for a discussion of the Exchange Transaction and the related accounting for the transaction.

For the nine month period ending September 30, 2017, we paid the interest payment for the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes in cash rather than in kind. These cash payments and the cash payments related to the 1.5 Lien Term Loan are reported in the financing section of the Condensed Consolidated Statements of Cash Flows. In addition, the cash interest payments on the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes lowered the carrying value of the respective notes under ACS 470-60, resulting in the recognition of a non-cash gain for the nine months ended September 30, 2017.

During 2018, the paid-in-kind option for the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes will expire in March 2018 and September 2018, respectively. Subsequent to the expiration of the paid-in-kind option, interest may only be paid in cash.

For the Third Lien PIK Toggle Notes and the 1.5 Lien Term Loan, the maturity of both will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes outstanding with a balance of $189.8 million are not extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. A total of $239.5 million would become due on February 28, 2019 if acceleration were to occur and, therefore, a total of $429.3 million would be due and payable during the first half of 2019 as the Unsecured Senior Notes are due in June 2019.

Credit Agreement. Our revolving bank credit facility matures in November 2018. Availability on our revolving bank credit facility as of September 30, 2017 was $149.7 million. At September 30, 2017 and December 31, 2016, no amounts were outstanding and letters of credit were minimal. During the nine months ended September 30, 2017, no borrowings were made on the revolving bank credit facility.

Availability under our revolving bank credit facility is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. The 2017 spring redetermination reaffirmed the borrowing base amount at $150.0 million. Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. The revolving bank credit facility is secured and is collateralized by substantially all of our oil and natural gas properties.

The Credit Agreement contains financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on financial ratios, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement and the other debt instruments as of September 30, 2017.

Long-Term Debt. The recorded amounts of our long-term debt and the primary terms are disclosed in *Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

BOEM Matters. As of the filing date of this Form 10-Q, the Company is in compliance with its financial assurance obligations to the BOEM and has no outstanding BOEM orders related to assurance obligations. We and other offshore Gulf of Mexico producers may, in the ordinary course of business, receive demands in the future for financial assurances from the BOEM.

Surety Bond Collateral. Some of the sureties that provide us surety bonds used for supplemental financial assurance purposes have requested and received collateral from us, and may request additional collateral from us in the future, which could be significant and could impact our liquidity. In addition, pursuant to the terms of our agreements with various sureties under our existing bonds or under any additional bonds we may obtain, we are required to post collateral at any time, on demand, at the surety's discretion.

The issuance of any additional surety bonds or other security to satisfy future BOEM orders, collateral requests from surety bond providers, and collateral requests from other third-parties may require the posting of cash collateral, which may be significant, and may require the creation of escrow accounts.

Cash Flow and Working Capital. Net cash provided by operating activities for the nine months ended September 30, 2017 was $130.3 million compared to net cash used by operating activities for the nine months ended September 30, 2016 of $9.2 million. Cash flows from operating activities were $171.9 million for the nine months ended September 30, 2017, (before changes in working capital, insurance reimbursements, escrow deposits and ARO), compared to $42.8 million in the comparable period. The increase in cash flows was primarily due to higher realized prices for all our commodities - oil, NGLs and natural gas, lower operating costs and lower interest payments. Our combined average realized sales price per Boe increased 32.0% in the nine months ended September 30, 2017, which caused total revenues to increase $82.6 million, partially offset by decreases of 4.6% in production volumes. Lease operating expenses decreased $11.8 million, and interest expense, net of amounts capitalized, (the portion of interest that is including in net cash provided by operating activities) decreased $46.5 million. Interest payments related to the New Debt are reported within cash flows from financing activities under ASC 470-60.

Other items affecting operating cash flows for the nine months ended September 30, 2017 were ARO settlements of $56.2 million (essentially the same as in the prior year period) and the escrow payment related to the Apache lawsuit of $49.5 million, partially offset by insurance reimbursements of $31.7 million and changes in receivables, accounts payable and accrued liabilities of $32.4 million.

Net cash used in investing activities during the nine months ended September 30, 2017 and 2016 was $74.3 million and $60.1 million, respectively, which represents our investments in oil and gas properties and equipment. There were no acquisitions of properties during either period. Investments in oil and natural gas properties on an accrual basis in the nine months ended September 30, 2017 were $79.1 million compared to $24.1 million for the same period in 2016. The capital expenditures during the nine months ended September 30, 2017 related primarily to investments on the conventional shelf. In addition, adjustments from working capital changes associated with investing activities was a net cash increase of $5.7 million in the nine months ended September 30, 2017 compared to net cash decrease of $37.4 million for the same period in 2016. These amounts represent timing differences between when the work was performed and the payment made. During the nine months ended September 30, 2016, assets sales were $1.5 million.

Net cash used by financing activities for the nine months ended September 30, 2017 was $20.1 million and net cash provided by financing activities for the nine months ended September 30, 2016 was $57.2 million. The net cash used for the nine months ended September 30, 2017 was primarily attributable to the interest payments on the 1.5 Lien Term Loan, the Second Lien PIK Toggle Notes, and the Third Lien PIK Toggle Notes, which are reported as financing activities under ASC 470-60. The net cash provided for the nine months ended September 30, 2016 was attributable to the issuance of the 1.5 Lien Term Loan, partially offset by costs related to the Debt Exchange transaction. –

Derivative Financial Instruments. From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of September 30, 2017, we had outstanding open derivatives for crude oil and natural gas. These derivatives provide downside protection against a portion of our remaining 2017 production. The oil swap contract provides cash inflows when the oil price is below $55.25. The "two-way collar" contracts will provide cash inflows when crude oil or natural gas prices are below $50.00 per barrel and $3.07 per MMBtu, respectively, in a month. Conversely, these contracts may require cash payments and limit upside potential if prices exceed certain amounts. See *Financial Statements - Note 5 - Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q for additional information.

Insurance Coverage. We currently carry multiple layers of insurance coverage in our Energy Package (defined as certain insurance policies relating to our oil and gas properties which include named windstorm coverage) covering our operating activities, with higher limits of coverage for higher valued properties and wells. The current policy limits for well control range from $30.0 million to $500.0 million depending on the risk profile and contractual requirements. With respect to coverage for named windstorms, we have a $150.0 million aggregate limit covering all of our properties, subject to a retention (deductible) of $30.0 million. Included within the $150.0 million aggregate limit is total loss only ("TLO") coverage on our Mahogany platform, which has no retention. The operational and named windstorm coverages are effective until June 1, 2018. Coverage for pollution causing a negative environmental impact is provided under the well control and other sections within the policy.

Our general and excess liability policies are effective until May 1, 2018 and provide for $300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility requirement under the Oil Pollution Act of 1990, we are required to evidence $150.0 million of financial responsibility to the BSEE and we have insurance coverage of such amount.

Although we were able to renew our general and excess liability policies effective on May 1, 2017, and our Energy Package effective on June 1, 2017, our insurers may not continue to offer this type and level of coverage to us in the future, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurers will not pay our claims. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

Capital Expenditures. The level of our investment in oil and natural gas properties changes from time to time depending on numerous factors, including the prices of oil, NGLs and natural gas, acquisition opportunities, available liquidity and the results of our exploration and development activities. The following table presents our capital expenditures on an accrual basis for exploration, development and other leasehold costs and acquisitions:

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In thousands)	
Exploration (1)	$ 20,458	$ 10,770
Development (1)	57,397	10,744
Seismic, capitalized interest, and other	1,233	2,548
Investments in oil and gas property/equipment	$ 79,088	$ 24,062

(1) Reported geographically in the subsequent table

The following table presents our exploration and development capital expenditures on an accrual basis geographically in the Gulf of Mexico:

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In thousands)	
Conventional shelf	$ 75,463	$ 17,234
Deepwater	2,392	4,390
Deep shelf	—	(110)
Exploration and development capital expenditures	$ 77,855	$ 21,514

Our capital expenditures for the nine months ended September 30, 2017 were financed by cash flow from operations and cash on hand.

The following table presents our offshore wells drilled based on a completed basis:

	Nine Months Ended September 30, 2017		2016	
	Gross	Net	Gross	Net
Development wells - Productive	3	3.0	—	—
Exploration wells - Productive	—	—	1	0.5
Total wells	3	3.0	1	0.5

All wells in the above table were successful.

Exploration/Development Activities. During the first quarter of 2017, the A-18 well at Mahogany was completed and began producing in January 2017. At March 31, 2017, the A-16 BP1 well at Mahogany was completed and began producing in April 2017. In June 2017, the A-8 well at Mahogany was completed and began producing in July 2017. As of October 30, 2017, we had three offshore wells in various stages of drilling activity.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. During the nine months ended September 30, 2017, we did not have any property sales.

Capital Expenditure Budget and Expected Production for 2017. With consideration of the current commodity price environment and the outlook for the remainder of 2017, our 2017 capital expenditure budget remains unchanged at $125.0 million, which excludes potential acquisitions. Although this is an increase from the $48.6 million capital expenditures incurred in 2016, our current plan for 2017 is a significant reduction from 2015 and 2014 investment levels of $231.4 million and $630.0 million, respectively. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments. We have limited flexibility for the remaining 2017 capital expenditure budget as we have contracted, or are in the process, of contracting rigs for the drilling program in the fourth quarter of 2017. Our fourth quarter 2017 capital expenditure projects will not have a significant impact on our 2017 production levels, but rather will help boost production levels beyond 2017. Our 2017 production is expected to be somewhat below 2016 levels as the current year has been impacted by well maintenance, weather, pipeline outages, and platform maintenance that collectively resulted in deferred production of almost 4,900 Boe per day in the third quarter of 2017. The impact to our production from hurricanes Harvey in September and Nate in October is estimated to be approximately one and five days of production, respectively.

Income Taxes. As of September 30, 2017, we have recorded current income tax receivables of $11.6 million and non-current income tax receivables of $52.1 million. The current income tax receivables relates primarily to an estimated NOL claim for 2017, which is expected to be received during the third quarter of 2018. During the nine months ended September 30, 2017, we received $11.9 million of income tax refunds related primarily to an NOL claim carried back to 2006. The non-current income taxes receivables relates to our NOL claims for the years 2012, 2013 and 2014 that were carried back to prior years and are expected to be received in the fourth quarter of 2018. These receivables relate to claims made pursuant to IRC Section 172(f), (related to rules for “specified liability losses”) which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. For 2017, we do not expect to make any significant income tax payments. See *Financial Statements – Note 7 – Income Taxes* under Part I, Item 1 of this Form 10-Q for additional information.

Asset Retirement Obligations. Each quarter, we review and revise our ARO estimates. Our ARO at September 30, 2017 and December 31, 2016 were $305.0 million and $334.4 million, respectively. Our plans include spending $69.8 million in 2017 for ARO compared to $72.3 million spent on ARO in 2016. As our ARO are estimates for work to be performed in the future, and in the case of our non-current ARO, are for many years in the future, actual expenditures could be substantially different than our estimates. See *Risk Factors*, under Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016 for additional information.

Contractual Obligations. Updated information on certain contractual obligations is provided in *Financial Statements – Note 2 – Long-Term* and *Note 4 – Asset Retirement Obligation,* and under Part I, Item 1 of this Form 10-Q. As of September 30, 2017, drilling rig commitments, excluding ARO drilling rig commitments, were approximately $9.8 million compared to $4.4 million as of December 31, 2016. Except for scheduled utilization, other contractual obligations as of September 30, 2017 did not change materially from the disclosures in *Management’s Discussion and Analysis of Financial Condition and Results of Operations,* under Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2016.

Critical Accounting Policies

Our significant accounting policies are summarized in *Financial Statements and Supplementary Data* under Part II, Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2016. Also refer to *Financial Statements - Note 1 - Basis of Presentation* under Part 1, Item 1 of this Form 10-Q.

Recent Accounting Pronouncements

See *Financial Statements - Note 1 - Basis of Presentation* under Part 1, Item 1, of this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the nine months ended September 30, 2017 did not change materially from the disclosures in *Quantitative and Qualitative Disclosures About Market Risk* under Part II, Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2016. As such, the information contained herein should be read in conjunction with the related disclosures in our Annual Report on Form 10-K for the year ended December 31, 2016.

Commodity Price Risk. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil, NGLs and natural gas, which fluctuate widely. Oil, NGLs and natural gas price declines have adversely affected our revenues, net cash provided by operating activities and profitability and could have further impact on our business in the future. As of September 30, 2017, we had open derivative contracts related to a portion of our estimated production for the remainder of 2017. We historically have not designated our commodity derivatives as hedging instruments and any future derivative commodity contracts are not expected to be designated as hedging instruments. Use of these contracts may reduce the effects of volatile oil and natural gas prices, but they also may limit future income from favorable price movements. See *Financial Statements - Note 5 - Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q for additional information.

Interest Rate Risk. As of September 30, 2017, we had no outstanding borrowings on our revolving bank credit facility. The revolving bank credit facility has a variable interest rate, which is primarily impacted by the London Interbank Offered Rate and the margin, which ranges from 3.00% to 4.00% depending on the amount outstanding. As of September 30, 2017, we did not have any derivative instruments related to interest rates.

Item 4. Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC and that any material information relating to us is accumulated and communicated to our management, including our Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”), as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by Exchange Act Rule 13a-15(b), we performed an evaluation, under the supervision and with the participation of our management, including our CEO and CFO, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, our CEO and CFO have each concluded that as of September 30, 2017, our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that our controls and procedures are designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

During the quarter ended September 30, 2017, there was no change in our internal control over financial reporting that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, *Financial Statements – Note 9 – Contingencies*, of this Form 10-Q for information on various legal matters.

Item 1A. Risk Factors

Investors should carefully consider the risk factors included under Part I, Item 1A, *Risk Factors,* in our Annual Report on Form 10-K for the year ended December 31, 2016, together with all of the other information included in this document, in our Annual Report on Form 10-K and in our other public filings, press releases and discussions with our management.

The potential effects of the continued weakness in crude oil prices are discussed under Part I, Item 1A, *Risk Factors,* in our Annual Report on Form 10-K for the year ended December 31, 2016 and also discussed in the Part I, Item 2, *Management's Discussion and Analysis of Financial Condition* and *Results of Operations* in the *Overview* section of this Form 10-Q.

Notwithstanding the matters discussed herein, there have been no material changes in our risk factors as previously disclosed in Part I, Item 1A, *Risk Factors,* in our Annual Report on Form 10-K for the year ended December 31, 2016.

Item 6. Exhibits

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed February 24, 2006 (File No. 001-32414))
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
3.3	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q, filed July 31, 2012 (File No. 001-32414))
3.4	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc., dated as of September 6, 2016. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed September 6, 2016 (File No. 001-32414))
31.1*	Section 302 Certification of Chief Executive Officer.
31.2*	Section 302 Certification of Chief Financial Officer.
32.1*	Section 906 Certification of Chief Executive Officer and Chief Financial Officer.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Label Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* Filed or Furnished herewith.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on November 2, 2017.

W&T OFFSHORE, INC.

By: /s/ JOHN D. GIBBONS

John D. Gibbons

Senior Vice President and Chief Financial Officer

(Principal Financial Officer), duly authorized to sign on behalf of the registrant

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Tracy W. Krohn, certify that:

1. I have reviewed this quarterly report on Form 10-Q of W&T Offshore, Inc. (the "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 the 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.

Date: November 2, 2017

/s/ Tracy W. Krohn

Tracy W. Krohn
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John D. Gibbons, certify that:

1. I have reviewed this quarterly report on Form 10-Q of W&T Offshore, Inc. (the "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 the 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.

Date: November 2, 2017

/s/ John D. Gibbons

John D. Gibbons
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of W&T Offshore, Inc. (the "Company"), hereby certifies, to the best of his knowledge, that the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2017 fully complies with the requirements of Section 13(a) or 15(d) of the Exchange Act and that information contained in such Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 2, 2017

/s/ Tracy W. Krohn

Tracy W. Krohn
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

Date: November 2, 2017

/s/ John D. Gibbons

John D. Gibbons
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)