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

## Form 10-Q

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

**For the quarterly period ended June 30, 2018**

**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**<br>**(State of incorporation)** | **72-1121985**<br>**(IRS Employer Identification Number)** |
| **Nine Greenway Plaza, Suite 300**<br>**Houston, Texas**<br>**(Address of principal executive offices)** | **77046-0908**<br>**(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<br>(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 July 31, 2018, there were 139,153,798 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

## PART I – FINANCIAL INFORMATION

### Item 1. Financial Statements

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

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| | (Unaudited) | |
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 129,440 | $ 99,058 |
| Receivables: | | |
| Oil and natural gas sales | 52,073 | 45,443 |
| Joint interest | 19,366 | 19,754 |
| Income taxes | 65,240 | 13,006 |
| Total receivables | 136,679 | 78,203 |
| Prepaid expenses and other assets (Note 1) | 20,470 | 13,419 |
| Total current assets | 286,589 | 190,680 |
| Oil and natural gas properties and other, net - at cost: (Note 1) | 576,073 | 579,016 |
| Restricted deposits for asset retirement obligations | 26,072 | 25,394 |
| Income taxes receivable | — | 52,097 |
| Other assets (Note 1) | 69,418 | 60,393 |
| Total assets | $ 958,152 | $ 907,580 |
| **Liabilities and Shareholders' Deficit** | | |
| Current liabilities: | | |
| Accounts payable | $ 46,464 | $ 83,665 |
| Undistributed oil and natural gas proceeds | 22,649 | 20,129 |
| Asset retirement obligations | 27,923 | 23,613 |
| Current maturities of long-term debt: (Note 2) | | |
| Principal | 189,829 | — |
| Carrying value adjustments | 34,917 | 22,925 |
| Current maturities of long-term debt - carrying value | 224,746 | 22,925 |
| Accrued liabilities (Note 1) | 20,505 | 17,930 |
| Total current liabilities | 342,287 | 168,262 |
| Long-term debt: (Note 2) | | |
| Principal | 713,365 | 889,790 |
| Carrying value adjustments | 47,605 | 79,337 |
| Long term debt, less current portion - carrying value | 760,970 | 969,127 |
| Asset retirement obligations, less current portion | 289,297 | 276,833 |
| Other liabilities (Note 1) | 73,007 | 66,866 |
| Commitments and contingencies (Note 11) | — | — |
| Shareholders' deficit: | | |
| Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at June 30, 2018 and December 31, 2017 | — | — |
| Common stock, $0.00001 par value; 200,000,000 shares authorized; 142,022,971 issued and 139,153,798 outstanding at June 30, 2018 and 141,960,462 issued and 139,091,289 outstanding December 31, 2017 | 1 | 1 |
| Additional paid-in capital | 548,196 | 545,820 |
| Retained earnings (deficit) | (1,031,439) | (1,095,162) |
| Treasury stock, at cost; 2,869,173 shares at June 30, 2018 and December 31, 2017 | (24,167) | (24,167) |
| Total shareholders' deficit | (507,409) | (573,508) |
| Total liabilities and shareholders' deficit | $ 958,152 | $ 907,580 |

See Notes to Condensed Consolidated Financial Statements.

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| | (In thousands except per share data) (Unaudited) | | | |
| Revenues: | | | | |
| Oil | $ 116,618 | $ 85,622 | $ 213,924 | $ 170,593 |
| NGLs | 8,734 | 7,054 | 18,394 | 15,796 |
| Natural gas | 22,977 | 29,258 | 48,844 | 59,016 |
| Other | 1,283 | 1,389 | 2,663 | 2,311 |
| Total revenues | 149,612 | 123,323 | 283,825 | 247,716 |
| Operating costs and expenses: | | | | |
| Lease operating expenses | 35,582 | 31,519 | 72,425 | 71,683 |
| Production taxes | 439 | 449 | 894 | 964 |
| Gathering and transportation | 4,928 | 5,318 | 9,985 | 11,527 |
| Depreciation, depletion, amortization and accretion | 39,757 | 40,364 | 77,838 | 80,354 |
| General and administrative expenses | 14,220 | 16,474 | 29,258 | 29,748 |
| Derivative (gain) loss | 6,219 | (3,689) | 6,219 | (7,644) |
| Total costs and expenses | 101,145 | 90,435 | 196,619 | 186,632 |
| Operating income | 48,467 | 32,888 | 87,206 | 61,084 |
| Interest expense | 12,147 | 11,436 | 23,470 | 22,730 |
| Gain on exchange of debt | — | 8,056 | — | 7,811 |
| Other (income) expense, net | 125 | 5,168 | (208) | 5,114 |
| Income before income tax expense (benefit) | 36,195 | 24,340 | 63,944 | 41,051 |
| Income tax expense (benefit) | 112 | (8,975) | 221 | (16,563) |
| Net income | $ 36,083 | $ 33,315 | $ 63,723 | $ 57,614 |
| Basic and diluted earnings per common share | $ 0.25 | $ 0.23 | $ 0.44 | $ 0.40 |

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, 2017 | 139,091 | $ 1 | $ 545,820 | $ (1,095,162) | 2,869 | $ (24,167) | $ (573,508) |
| Share-based compensation | — | — | 2,434 | — | — | — | 2,434 |
| Stock Issued | 63 | — | — | — | — | — | — |
| RSUs surrendered for payroll taxes | — | — | (58) | — | — | — | (58) |
| Net income | — | — | — | 63,723 | — | — | 63,723 |
| Balances at June 30, 2018 | 139,154 | $ 1 | $ 548,196 | $ (1,031,439) | 2,869 | $ (24,167) | $ (507,409) |

See Notes to Condensed Consolidated Financial Statements.

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

| | Six Months Ended June 30, 2018 | Six Months Ended June 30, 2017 |
|---|---|---|
| | (In thousands) (Unaudited) | |
| **Operating activities:** | | |
| Net income | $ 63,723 | $ 57,614 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion, amortization and accretion | 77,838 | 80,354 |
| Gain on exchange of debt | — | (7,811) |
| Amortization of debt items and other items | 1,126 | 836 |
| Share-based compensation | 2,434 | 3,466 |
| Derivative (gain) loss | 6,219 | (7,644) |
| Cash receipts (payments) on derivative settlements, net | (1,149) | 2,208 |
| Deferred income taxes | 221 | 212 |
| Changes in operating assets and liabilities: | | |
| Oil and natural gas receivables | (6,630) | 3,675 |
| Joint interest receivables | 251 | 1,965 |
| Insurance reimbursements | — | 30,100 |
| Income taxes | (138) | (16,960) |
| Prepaid expenses and other assets | (14,323) | (3,575) |
| Escrow deposit - Apache lawsuit | — | (49,500) |
| Asset retirement obligation settlements | (12,124) | (36,021) |
| Accounts payable, accrued liabilities and other | (2,256) | 6,666 |
| Net cash provided by operating activities | 115,192 | 65,585 |
| **Investing activities:** | | |
| Investment in oil and natural gas properties and equipment | (31,803) | (43,800) |
| Changes in operating assets and liabilities associated with investing activities | (29,330) | (827) |
| Acquisition of property interest | (16,617) | — |
| Purchases of furniture, fixtures and other | — | (853) |
| Net cash used in investing activities | (77,750) | (45,480) |
| **Financing activities:** | | |
| Payment of interest on 1.5 Lien Term Loan | (4,114) | (4,113) |
| Payment of interest on 2nd Lien PIK Toggle Notes | (2,920) | (7,335) |
| Payment of interest on 3rd Lien PIK Toggle Notes | — | (6,201) |
| Other | (26) | (372) |
| Net cash used in financing activities | (7,060) | (18,021) |
| Increase in cash and cash equivalents | 30,382 | 2,084 |
| Cash and cash equivalents, beginning of period | 99,058 | 70,236 |
| Cash and cash equivalents, end of period | $ 129,440 | $ 72,320 |

See Notes to Condensed Consolidated Financial Statements.

## 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") and through our proportionately consolidated interest in Monza Energy LLC, as described in more detail below under the subheading "-Recent Events" in this Note and in Note 4.

***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, 2017.

***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 realized prices of crude oil and NGLs improved during the six months ended June 30, 2018 compared to the average realized prices in the six months ended June 30, 2017.

Our Fifth Amended and Restated Credit Agreement (as amended, the "Credit Agreement") provides our revolver bank credit facility and matures on November 8, 2018. As of June 30, 2018, we had $9.7 million of letters of credit outstanding and no amounts borrowed on our revolving bank credit facility. Our 8.500% Senior Notes (the "Unsecured Senior Notes") mature on June 15, 2019. If the Unsecured Senior Notes have not been extended, refunded, defeased, discharged, replaced or refinanced by February 28, 2019, then the 11.00% 1.5 Lien Term Loan, due November 15, 2019 (the "1.5 Lien Term Loan") and the 8.50%/10.00% Third Lien Payment-In-Kind ("PIK") Toggle Notes, due June 15, 2021, (the "Third Lien PIK Toggle Notes") will both accelerate their maturity to February 28, 2019. During the remainder of 2018, we plan to address the issues of the potential maturity acceleration of these two debt instruments and to extend or replace the revolving bank credit facility. We expect to build sufficient cash balances in 2018 to be able to redeem, repurchase or refinance the Unsecured Senior Notes. Certain amendments under the Credit Agreement and the 1.5 Lien Term Loan will likely be required in the event we redeem or repurchase the Unsecured Senior Notes, which we anticipate would be granted if requested. If we are in a position to repay or refinance the 1.5 Lien Term Loan, then we would expect to extend the maturity of our revolving bank credit facility. There can be no assurance that lenders will extend our revolving bank credit facility maturity, but under current market conditions and based on the outlook of our cash position in 2018 and further, we believe our lenders or replacement lenders will be amenable to participating in a refinancing or other corporate financing transaction.

In addition to the assessment of potential maturity acceleration of certain debt instruments discussed above, we have assessed our obligations, our financial condition, the current capital markets and options given different scenarios of commodity prices. We believe we will have adequate available liquidity to fund our operations through August 2019, the period of assessment to qualify as a going concern. However, we cannot predict the potential changes in commodity prices or future Bureau of Ocean Energy Management ("BOEM") 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, 2017 concerning risks related to our business and events occurring during 2017 and other information and the Notes herein for additional information.

***Accounting Standard Updates Effective January 1, 2018.*** Accounting Standards Update No. 2016-18, ("ASU 2016-18"), *Statement of Cash Flows (Topic 230) – Restricted Cash* became effective for us as of January 1, 2018. As we did not have any amounts of restricted cash in the six months ended June 30, 2018 and 2017, ASU 2016-18 did not affect the Condensed Consolidated Statement of Cash Flows.

Accounting Standards Update No. 2017-01, ("ASU 2017-01"), *Business Combinations (Topic 805) – Clarifying the Definition of a Business* became effective for us as of January 1, 2018. The new guidance is intended to assist with the evaluation of whether a set of transferred assets and activities is a business. In application of the revised guidance under ASU 2017-01 for our acquisition of a non-operated interest in the Heidelberg field described in Note 5, we determined the transaction should be treated as an asset purchase rather than the purchase of a business.

Accounting Standard Update No. 2014-09, ("ASU 2014-09") *Revenue from Customers (Topic 606)*, became effective for us in the period ending March 31, 2018. We reviewed our contracts using the five-step revenue recognition model, which did not identify any changes required as to the amount or timing of revenue recognition. We adopted the new standard using the modified retrospective approach which did not result in any cumulative-effect adjustment on the date of adoption. The implementation of ASU 2014-09 resulted in a change in our reporting in the Condensed Consolidated Statement of Operations so that we now report revenue streams separately for crude oil, NGLs, natural gas and other revenues in compliance with the new standard.

***Revenue Recognition***. We recognize revenue from the sale of crude oil, NGLs, and natural gas when our performance obligations are satisfied. Our contracts with customers are primarily short-term (less than 12 months). Our responsibilities to deliver a unit of crude oil, NGL, and natural gas under these contracts represent separate, distinct performance obligations. These performance obligations are satisfied at the point in time control of each unit is transferred to the customer. Pricing is primarily determined utilizing a particular pricing or market index, plus or minus adjustments reflecting quality or location differentials.

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

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Prepaid/accrued insurance | $ 4,526 | $ 2,401 |
| Surety bond unamortized premiums | 3,305 | 2,676 |
| Prepaid deposits related to royalties | 8,391 | 6,456 |
| Advances for capital expenditures | 1,098 | — |
| Derivative contract premiums | 1,582 | — |
| Other | 1,568 | 1,886 |
| Prepaid expenses and other assets | $ 20,470 | $ 13,419 |

***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):

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Oil and natural gas properties and equipment | $ 8,167,664 | $ 8,102,044 |
| Furniture, fixtures and other | 21,831 | 21,831 |
| Total property and equipment | 8,189,495 | 8,123,875 |
| Less accumulated depreciation, depletion and amortization | 7,613,422 | 7,544,859 |
| Oil and natural gas properties and other, net | $ 576,073 | $ 579,016 |

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

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Escrow deposit - Apache lawsuit | $ 49,500 | $ 49,500 |
| Appeal bond deposits | 6,925 | 6,925 |
| Investment in White Cap, LLC | 2,648 | 2,511 |
| Deposit related to the Credit Agreement | 4,702 | — |
| Unamortized brokerage fee for Monza | 2,182 | — |
| Proportional consolidation of Monza's other assets (Note 4) | 2,301 | — |
| Other | 1,160 | 1,457 |
| Total other assets | $ 69,418 | $ 60,393 |

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

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Accrued interest | $ 4,199 | $ 4,200 |
| Accrued salaries/payroll taxes/benefits | 2,996 | 2,454 |
| Incentive compensation plans | 3,987 | 7,366 |
| Litigation accruals | 3,604 | 3,480 |
| Derivative contracts | 5,281 | — |
| Other | 438 | 430 |
| Total accrued liabilities | $ 20,505 | $ 17,930 |

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

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Apache lawsuit | $ 49,500 | $ 49,500 |
| Uncertain tax positions including interest/penalties | 11,236 | 11,015 |
| Dispute related to royalty deductions | 4,687 | — |
| Dispute related to royalty-in-kind | 2,083 | 914 |
| Other | 5,501 | 5,437 |
| Total other liabilities (long-term) | $ 73,007 | $ 66,866 |

***Recent Accounting Developments.*** 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 financing or operating lease. However, unlike current GAAP, which requires only capital or financing 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. 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. Our current operating leases that will be impacted by ASU 2016-02 are leases for office space, which is primarily in Houston, Texas, 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. 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 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. 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. As we do not designate our commodity derivative instruments 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.

**2. Long-Term Debt**

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

| | June 30, 2018 | | | December 31, 2017 | | |
|---|---|---|---|---|---|---|
| | 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 | — | 11,482 | 11,482 | — | 15,596 | 15,596 |
| Subtotal | 75,000 | 11,482 | 86,482 | 75,000 | 15,596 | 90,596 |
| 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 | 177,513 | — | 177,513 | 171,769 | — | 171,769 |
| Future payments-in-kind | — | — | — | — | 5,745 | 5,745 |
| Future interest payments | — | 31,952 | 31,952 | — | 34,872 | 34,872 |
| Subtotal | 177,513 | 31,952 | 209,465 | 171,769 | 40,617 | 212,386 |
| 8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021: | | | | | | |
| Principal | 160,852 | — | 160,852 | 153,192 | — | 153,192 |
| Future payments-in-kind | — | 3,664 | 3,664 | — | 11,323 | 11,323 |
| Future interest payments | — | 38,682 | 38,682 | — | 38,682 | 38,682 |
| Subtotal | 160,852 | 42,346 | 203,198 | 153,192 | 50,005 | 203,197 |
| 8.50% Unsecured Senior Notes, due June 2019 | 189,829 | — | 189,829 | 189,829 | — | 189,829 |
| Debt premium, discount, issuance costs, net of amortization | — | (3,258) | (3,258) | — | (3,956) | (3,956) |
| Total long-term debt | 903,194 | 82,522 | 985,716 | 889,790 | 102,262 | 992,052 |
| Current maturities of long-term debt (2) | 189,829 | 34,917 | 224,746 | — | 22,925 | 22,925 |
| Long term debt, less current maturities | $ 713,365 | $ 47,605 | $ 760,970 | $ 889,790 | $ 79,337 | $ 969,127 |

(1) Future interest payments and future payments-in-kind are recorded on an undiscounted basis.
(2) Represents principal of the 8.50% Unsecured Senior Notes due June 15, 2019 and future interest payments on the 1.5 Lien Term Loan, Second Lien PIK Toggle Notes and Third Lien PIK Toggle Notes due within twelve months.

***Accounting for Certain Debt Instruments***

We accounted for a transaction executed on September 7, 2016 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 9.00/ 10.75% Second Lien PIK Toggle Notes, due May 15, 2020, (the "Second Lien PIK Toggle Notes"); the Third Lien PIK Toggle Notes and 1.5 Lien Term Loan (the "New Debt") are 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 for the periods presented. 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.

The primary terms of our long-term debt are described below:

***Credit Agreement.*** The Credit Agreement provides a revolving bank credit facility and expires by its term on November 8, 2018. 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, as defined in the Credit Agreement, 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.
- To the extent there are borrowings, they are primarily 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.

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 2018 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.

As of June 30, 2018 and December 31, 2017, we did not have any borrowings outstanding on the revolving bank credit facility and had $9.7 million and $0.3 million of letters of credit outstanding, respectively. Available credit as of June 30, 2018 was $140.3 million. As of June 30, 2018, we have deposited $4.7 million with the lead bank in compliance with the terms of the Credit Agreement as letters of credit are considered borrowings and our unrestricted cash balance exceeded $35.0 million.

***1.5 Lien Term Loan.*** In September 2016, we entered into the 1.5 Lien Term Loan 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 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. The 1.5 Lien Term Loan contains various covenants that limit, among other things, our ability to: (i) pay cash dividends; (ii) repurchase the Unsecured Senior Notes at a price greater than 65% of par and limited to a basket of $35 million; (iii) repurchase our common stock; (iv) sell our assets; (v) make certain loans or investments; (vi) merge or consolidate; (vii) enter into certain liens; (viii) create liens that secure debt; and (ix) enter into transactions with affiliates.

***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 limit or prohibit 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 to us; (v) create liens that secure debt; (vi) enter into transactions with affiliates; and (vii) merge or consolidate with another company.

***Second Lien PIK Toggle Notes.*** In September 2016, we issued Second Lien PIK Toggle Notes with a maturity date of May 15, 2020. Interest is payable on May 15 and November 15 of each year. For the interest period from November 15, 2017 up to and including March 6, 2018, we had the option to pay all or a portion of interest in-kind at the rate of 10.75% per annum, which if so exercised, is added to the principal amount. After March 6, 2018, interest is payable in cash at the rate of 9.00% per annum. 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 and are effectively *pari passu* with the Second Lien Term Loan. The Second Lien PIK Toggle Notes and related Support Agreement contain covenants that limit or prohibit 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 to us; (v) create liens that secure debt; (vi) enter into transactions with affiliates; and (vii) merge or consolidate with another company.

***Third Lien PIK Toggle Notes.*** In September 2016, we issued Third Lien PIK Toggle Notes 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. Interest is payable on June 15 and December 15 of each year. For the interest periods up to and including September 6, 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. If so elected, such in-kind will be added to the principal amount. After September 6, 2018, interest is payable in cash at the rate of 8.50% per annum. 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. The Third Lien PIK Toggle Notes and related Support Agreement contain covenants that limit or prohibit 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 to us; (v) create liens that secure debt; (vi) enter into transactions with affiliates; and (vii) merge or consolidate with another company.

***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 8.4%, which includes amortization of premiums and debt issuance costs. The Unsecured Senior Notes contain covenants that limit or prohibit 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 to us; (v) create liens that secure debt; (vi) enter into transactions with affiliates; and (vii) merge or consolidate with another company.

***Covenants.*** We were in compliance with all applicable covenants for all of our debt instruments as of June 30, 2018.

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 fair value of the 1.5 Lien Term Loan was estimated using the carrying value of the principal as only one entity has been the holder of the 1.5 Lien Term Loan. 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 a very active market; therefore, the fair value is classified within Level 2.

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

| | Hierarchy | June 30, 2018 | December 31, 2017 |
|---|---|---|---|
| 11.00% 1.5 Lien Term Loan, due November 2019 | Level 2 | $ 75,000 | $ 75,000 |
| 9.00 % Second Lien Term Loan, due May 2020 | Level 2 | 300,000 | 288,000 |
| 9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020 | Level 2 | 177,513 | 162,322 |
| 8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021 | Level 2 | 153,614 | 119,490 |
| 8.50% Unsecured Senior Notes, due June 2019 | Level 2 | 187,931 | 178,439 |

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

## 4. JV Drilling Program

On March 12, 2018, W&T and two other initial members formed and initially funded a limited liability company, Monza Energy LLC, a Delaware limited liability company ("Monza"), that will jointly participate with us in the exploration, drilling and development of up to 14 identified drilling projects (the "JV Drilling Program") in the Gulf of Mexico over the next three years. W&T initially contributed 88.94% of its working interest in 14 identified undeveloped drilling projects to Monza and retained 11.06% of its working interest. The Monza board has approved the substitution of one of these identified undeveloped drilling projects, the Viosca Knoll 823 ("VK 823") A-14 well, with the VK 823 A-13 well, which is in the process of being contributed to Monza through the conveyance by W&T of 58.71% of its working interest in such well to Monza and retaining 41.29% of its working interest in such well. The interest in the VK823 A-14 well will be reconveyed to W&T. Since the initial closing, additional investors have joined as members of Monza and as of June 30, 2018, total commitments by all members, including W&T, are $361.4 million. Monza has closed off funding from additional investors. The JV Drilling Program is structured so that we initially receive an aggregate of 30.0% of the revenues less expenses, through both our direct ownership of our working interest in the projects and our indirect interest through our interest in Monza, for contributing 20.0% of the estimated total well costs plus associated leases and providing access to available infrastructure at agreed upon rates. W&T will be the operator of each well in the JV Drilling Program unless there is already a designated third-party operator.

The members of Monza are made up of third-party investors, W&T and an entity owned and controlled by Mr. Tracy W. Krohn, our Chairman and Chief Executive Officer. The Krohn entity invested as a minority investor on the same terms and conditions as the third-party investors and its investment is limited to 4.5% of total invested capital within Monza. The entity affiliated with Mr. Krohn has made a capital commitment to Monza of $14.5 million.

At the inception of Monza, W&T received a net reimbursement of approximately $20 million for the capital expenditures incurred prior to the close date for projects in the JV Drilling Program. W&T may be obligated to fund certain cost overruns, subject to certain exceptions, on JV Drilling Program wells above budgeted and contingency amounts. As of June 30, 2018, members of Monza made partner capital contribution payments to Monza totaling $89.4 million.

Information on the structure and relationship follows:

***Board Structure and Authority.*** Under the Monza limited liability agreement, the business and affairs of Monza are managed by a board of five directors, which will consist of three directors selected by the third-party investors, Mr. Krohn, and an additional independent director will be selected by a majority of the third-party investors in Monza which will be subject to consent by W&T. The day-to-day operations of Monza are being managed by W&T, under the direction of the Monza board, pursuant to a services agreement. W&T has no control over the decisions of the Monza board. W&T has veto rights for certain decisions, but does not have the ability to unilaterally make decisions for Monza, except for day-to-day decisions as permitted under the services agreement. The Monza board is responsible for the management of Monza and for making decisions with respect to its interest in the 14 drilling projects, including approval of the budgets.

***Accounting Methodology and Carrying Amounts.*** Our interest in Monza is considered to be a variable interest entity that we account for using proportional consolidation. We do not fully consolidate Monza because we are not considered the primary beneficiary and we utilize proportional consolidation to account for our interest in the Monza properties. As of June 30, 2018, in the Condensed Consolidated Balance Sheet, we recorded $6.0 million in oil and natural gas properties, $2.3 million in other assets and $1.7 million, net reduction in working capital in connection with our proportional interest in Monza's assets and liabilities. For the six months ended June 30, 2018, we recorded $0.5 million in revenue, $0.4 million in operating expense and $0.2 million in other expense in connection with our proportional interest in Monza's operations.

***Maximum Exposure.*** Our contribution to Monza as of June 30, 2018 was $48.8 million, which consisted of cash and the conveyance of the Company's working interest in the 14 projects. We may also take responsibility for certain drilling and completion cost overruns, subject to certain limitations and certain exceptions, of which the total exposure cannot be estimated at this time.

## 5. Heidelberg Field

On April 5, 2018, we closed on the purchase from Cobalt International Energy, Inc. of a 9.375% non-operated working interest in the Heidelberg field located in Green Canyon blocks 859, 903 and 904. The gross purchase price was $31.1 million which was adjusted for certain closing items and an effective date of January 1, 2018. Cash flows generated by the acquired interest between the effective date and the closing date reduced the net purchase price to $16.6 million on the closing date. We determined that the assets acquired did not meet the definition of a business; therefore, the transaction was accounted for as an asset acquisition. In connection with this transaction, we were required to furnish a letter of credit of $9.4 million to a pipeline company as consignee. We recognized ARO of $3.6 million as a component of the transaction. In conjunction with the purchase of an interest in the Heidelberg field, we assumed contracts with certain pipeline companies that contain minimum quantities obligations through 2028 resulting in an estimated commitment of $19.6 million.

**6. 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, 2017 | $ | 300,446 |
| Liabilities settled | | (12,124) |
| Accretion of discount | | 9,273 |
| Liabilities assumed through purchase | | 3,597 |
| Revisions of estimated liabilities (1) | | 16,028 |
| Balance, June 30, 2018 | | 317,220 |
| Less current portion | | 27,923 |
| Long-term | $ | 289,297 |

(1) Revisions were primarily related to wells that experienced sustained casing pressure issues. In addition, some properties experienced scope change.

**7. 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 crude oil and natural gas. Some 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.

During the second quarter of 2018, we entered into crude oil derivative contracts which relate to a portion of our expected crude oil production from May 2018 to December 2018. The crude oil contracts are based on West Texas Intermediate ("WTI") crude oil prices as quoted off the New York Mercantile Exchange ("NYMEX"). During the first quarter of 2017, we entered into commodity contracts for crude oil and natural gas, all of which had expired as of December 31, 2017.

As of June 30, 2018, our open crude oil derivative contracts were as follows:

**Crude Oil: Swap, Priced off WTI (NYMEX)**

| Termination Period | | Notional Quantity (Bbls/day) (1) | Notional Quantity (Bbls) (1) | Strike Price |
|---|---|---|---|---|
| 2018 | December | 2,000 | 368,000 | $ 63.80 |

**Crude Oil: Puts, Priced off WTI (NYMEX)**

| Termination Period | | Notional Quantity (Bbls/day) (1) | Notional Quantity (Bbls) (1) | Put Price |
|---|---|---|---|---|
| 2018 | December | 5,000 | 920,000 | $ 60.00 |

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

| Termination Period | | Notional Quantity (Bbls/day) (1) | Notional Quantity (Bbls) (1) | Contract Prices: Put Option (Bought) | Contract Prices: Call Option (Sold) |
|---|---|---|---|---|---|
| 2018 | December | 2,000 | 368,000 | $ 60.00 | $ 69.50 |
| 2018 | December | 2,000 | 368,000 | $ 55.00 | $ 72.75 |

(1) bbls = barrels

The swap and two-way collars were "cost-less" contracts, in that no premiums were paid or received. For the put option contract, the $2.1 million premium is being amortized over the life of the contract and recorded in *Prepaid and other assets* on the Condensed Consolidated Balance Sheet. See Note 1.

Our open and closed (not settled) commodity derivative contracts were recorded within the line*Accrued liabilities* on the Condensed Consolidated Balance Sheet summarized in the following table (in thousands):

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Open contracts | $ 5,070 | $ — |
| Closed contracts - not settled | 211 | 84 |
| Total contracts | $ 5,281 | $ 84 |

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

| | Three Months Ended June 30, 2018 | Three Months Ended June 30, 2017 | Six Months Ended June 30, 2018 | Six Months Ended June 30, 2017 |
|---|---|---|---|---|
| Derivative (gain) loss | $ 6,219 | $ (3,689) | $ 6,219 | $ (7,644) |

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

| | Six Months Ended June 30, | |
|---|---|---|
| | 2018 | 2017 |
| Cash receipts (payments) on derivative settlements, net | $ (1,149 ) | $ 2,208 |

***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 some 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. As of June 30, 2018, there would have been no difference in the presentation of our commodity derivatives on a gross or net basis.

## 8. 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 2017 and 2016, 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 June 30, 2018, there were 13,342,827 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. The Company plans to settle RSUs that vest in the future using shares of common stock.

RSUs currently outstanding related to the 2017 and 2016 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. See the 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 and 2016 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 six months ended June 30, 2018 is as follows:

| | Restricted Stock Units | |
|---|---|---|
| | Units | Weighted Average Grant Date Fair Value Per Unit |
| Nonvested, December 31, 2017 | 5,765,251 | $ 2.48 |
| Vested | (28,503 ) | 2.38 |
| Forfeited/adjustments | (45,017 ) | 2.47 |
| Nonvested, June 30, 2018 | 5,691,731 | 2.48 |

For the outstanding RSUs issued to the eligible employees as of June 30, 2018, vesting is expected to occur as follows:

| | Restricted Stock Units |
|---|---|
| 2018 | 3,698,748 |
| 2019 | 1,992,983 |
| Total | 5,691,731 |

***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 2018, 2017 and 2016. As of June 30, 2018, there were 128,980 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 is as follows:

| | Restricted Shares | |
|---|---|---|
| | Shares | Weighted Average Grant Date Fair Value Per Share |
| Nonvested, December 31, 2017 | 246,528 | $ 2.27 |
| Granted | 41,544 | 6.74 |
| Vested | (106,240 ) | 2.64 |
| Nonvested, June 30, 2018 | 181,832 | 3.08 |

For the outstanding Restricted Shares issued to the non-employee directors as of June 30, 2018, vesting is expected to occur as follows:

| | Restricted Shares |
|---|---|
| 2019 | 105,012 |
| 2020 | 62,972 |
| 2021 | 13,848 |
| Total | 181,832 |

***Share-Based Compensation.*** Share-based compensation expense is recorded in the line *General and administrative expenses* in the Condensed Consolidated Statements of Operations. Share-based compensation was lower in the three and six months ended June 30, 2018 compared to the prior year period as no RSU awards have been granted yet as of June 30, 2018. A summary of incentive compensation expense under share-based payment arrangements and the related tax benefit is as follows (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Share-based compensation expense from: | | | | |
| Restricted stock units | $ 1,145 | $ 2,342 | $ 2,294 | $ 4,200 |
| Restricted Shares | 70 | 70 | 140 | 140 |
| Total | $ 1,215 | $ 2,412 | $ 2,434 | $ 4,340 |
| Share-based compensation tax benefit: | | | | |
| Tax benefit computed at the statutory rate | $ 255 | $ 844 | $ 511 | $ 1,519 |

***Unrecognized Share-Based Compensation.*** As of June 30, 2018, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $3.9 million and $0.5 million, respectively. Unrecognized share-based compensation expense will be recognized through November 2019 for RSUs and April 2021 for Restricted Shares.

***Cash-Based Incentive Compensation.*** In addition to share-based compensation, cash-based awards were granted under the Plan to substantially all eligible employees in 2017 and 2016. The cash-based awards, which are a short-term component of the Plan, are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each such criterion. In addition, these cash-based awards included an additional financial condition requiring Adjusted EBITDA less reported Interest Expense Incurred (as defined in the awards) for any fiscal quarter plus the three preceding quarters to exceed defined levels measured over defined time periods for each cash-based award. Expense is recognized over the service period once the business criteria, individual performance criteria and financial condition are met.

- For the 2017 cash-based awards, a portion of the business criteria and individual performance criteria were achieved. The financial condition requirement of Adjusted EBITDA less reported Interest Expense Incurred exceeding $200 million over four consecutive quarters was achieved; therefore, incentive compensation expense was recognized in 2017 and in the first two months of 2018 for the 2017 cash-based awards. Payments were made in March 2018.

- For the 2016 cash-based awards, the financial condition requirement of Adjusted EBITDA less reported Interest Expense Incurred exceeding $300 million over four consecutive quarters was not achieved as of June 30, 2018; therefore no expense was recognized during the six months ended June 30, 2018 or during 2017. The terms of the 2016 cash-based awards allow for the achievement of the financial condition up through December 31, 2018. If the financial condition is achieved, payment is to be made within 30 days of achievement of the financial condition.

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Share-based compensation included in: | | | | |
| General and administrative expenses | $ 1,215 | $ 2,412 | $ 2,434 | $ 4,340 |
| Cash-based incentive compensation included in: | | | | |
| Lease operating expense | 543 | 394 | 1,403 | 394 |
| General and administrative expenses | 1,391 | 1,004 | 4,063 | 1,004 |
| Total charged to operating income | $ 3,149 | $ 3,810 | $ 7,900 | $ 5,738 |

## 9. Income Taxes

Our income tax expense for the three and six months ended June 30, 2018 was $0.1 million and $0.2 million, respectively. Our income tax benefit for the three and six months ended June 30, 2017 was $9.0 million and $16.6 million, respectively. Our effective tax rate was not meaningful for the periods presented. Our current full-year forecast for 2018 has a net operating loss for tax purposes; therefore, no current tax expense was recorded related to the full-year forecast. In addition, no deferred income tax expense was recorded due to dollar-for-dollar offsets by our valuation allowance. The income tax benefit for the three months ended June 30, 2017 relates to net operating loss 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 six months ended June 30, 2018 and 2017, we did not receive any income tax refunds and made no income tax payments of significance.

As of June 30, 2018, we recorded current income taxes receivable of $65.2 million. As of December 31, 2017, the balance sheet reflected current income taxes receivable of $13.0 million and non-current income taxes receivable of $52.1 million. The receivables primarily relate to a net operating loss claim carried back for 2017 and net operating loss 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 require a review by the Congressional Joint Committee on Taxation.

As of June 30, 2018 and December 31, 2017, our valuation allowance was $158.1 million and $171.5 million, respectively, related to federal and state deferred tax 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 net operating losses are deductible. 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. Although our net deferred tax assets and the related valuation allowance reflect the provisions of the Tax Cuts and Jobs Act (“TCJA”), due to the timing and the complexity of the provisions of the TCJA, further adjustments may be required during 2018 in determination of the final effect in our financial statements.

The tax years 2013 through 2017 remain open to examination by the tax jurisdictions to which we are subject.

## 10. Earnings Per Share

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

| | Three Months Ended June 30, 2018 | Three Months Ended June 30, 2017 | Six Months Ended June 30, 2018 | Six Months Ended June 30, 2017 |
|---|---|---|---|---|
| Net income | $ 36,083 | $ 33,315 | $ 63,723 | $ 57,614 |
| Less portion allocated to nonvested shares | 1,474 | 1,374 | 2,621 | 2,442 |
| Net income allocated to common shares | $ 34,609 | $ 31,941 | $ 61,102 | $ 55,172 |
| Weighted average common shares outstanding | 138,929 | 137,552 | 138,892 | 137,533 |
| Basic and diluted earnings per common share | $ 0.25 | $ 0.23 | $ 0.44 | $ 0.40 |

## 11. Contingencies

***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 filed an appeal of the trial court judgment in the U.S. Court of Appeals for the Fifth Circuit. Prior to filing the appeal, in order to stay execution of the judgment, we deposited $49.5 million with the registry of the court in June 2017.

The deposit of $49.5 million with the registry of the court is recorded in *Other assets (*long-term) on the Condensed Consolidated Balance Sheets as of June 30, 2018 and December 31, 2017. Although we are appealing the decision, based solely on the decision rendered, we have recorded $49.5 million in *Other liabilities* (long-term) as of June 30, 2018 and December 31, 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. We were required to post a bond in the amount of $7.2 million and cash collateral of $6.9 million in order to appeal the IBLA decision.

**Royalties-In-Kind ("RIK").** Under a program with the Minerals Management Service ("MMS") (a Department of Interior agency and predecessor to the ONRR), royalties could be paid "in-kind" rather than in value from oil and gas companies operating under federal leases. We participated in the RIK program at our East Cameron 373 field beginning in November 2001, where in some months we over delivered volumes of natural gas and under delivered volumes of natural gas in other months for royalties owed. The MMS elected to terminate receiving in-kind in October 2008 causing the imbalance to become fixed for accounting purposes. The MMS ordered us to pay an amount based on its interpretation of the program and its calculations of amounts owed. We disagreed with MMS's interpretations and calculations and filed an appeal with the IBLA, of which the IBLA ruled in MMS' favor. We filed an appeal with the District Court of the Western District of Louisiana, who assigned the case to a magistrate to review and issue a ruling, and the District Court upheld the magistrate's ruling. Part of the ruling was in favor of our position and part was in favor of MMS' position. Based solely on the magistrate's ruling, we increased a liability reserve by $1.2 million from a previously recorded amount of $0.9 million recorded in 2012. We are appealing the ruling to the U.S. Fifth Circuit Court of Appeals.

***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 six months ended June 30, 2018 and 2017, we paid additional royalty payments of $0.3 million and $1.1 million, respectively. 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.*** During the six months ended June 30, 2018 and 2017, we did not pay any civil penalties to the Bureau of Safety and Environmental Enforcement ("BSEE") related to Incidents of Noncompliance ("INCs") at various offshore locations. We currently have five open civil penalties issued by the BSEE from INCs, which have not been settled as of the filing date of this Form 10-Q. The INCs underlying the civil penalties relate to separate offshore locations with occurrence dates ranging from July 2012 to June 2014. The proposed civil penalties for these INCs total $7.8 million. We have accrued approximately $3.4 million as of June 30, 2018, which is our best estimate of the final settlements 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.

***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 six months ended June 30, 2018.

***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.

**12. 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 a result of the JV Drilling Program, we recorded proportional consolidation adjustments, which are not considered a guarantor asset under our debt agreements and, accordingly, are reported as non-guarantor adjustments in the following tables. Due to the methodology of recording the ceiling-test write down in prior periods, consolidating adjustments are required to present the consolidated results appropriately.

**Condensed Consolidating Balance Sheet as of June 30, 2018**

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Adjustments | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ 129,440 | $ — | $ — | $ — | $ 129,440 |
| Receivables: | | | | | |
| Oil and natural gas sales | 8,109 | 44,161 | (197) | — | 52,073 |
| Joint interest | 19,366 | — | — | — | 19,366 |
| Income taxes | 193,594 | — | — | (128,354) | 65,240 |
| Total receivables | 221,069 | 44,161 | (197) | (128,354) | 136,679 |
| Prepaid expenses and other assets | 16,739 | 3,700 | 31 | — | 20,470 |
| Total current assets | 367,248 | 47,861 | (166) | (128,354) | 286,589 |
| | | | | | |
| Oil and natural gas properties and other, net | 416,539 | 121,075 | 48,003 | (9,544) | 576,073 |
| Restricted deposits for asset retirement obligations | 26,072 | — | — | — | 26,072 |
| Other assets | 607,463 | 544,029 | (46,464) | (1,035,610) | 69,418 |
| Total assets | $ 1,417,322 | $ 712,965 | $ 1,373 | $ (1,173,508) | $ 958,152 |
| **Liabilities and Shareholders' Equity (Deficit)** | | | | | |
| Current liabilities: | | | | | |
| Accounts payable | $ 38,445 | $ 6,457 | $ 1,562 | $ — | $ 46,464 |
| Undistributed oil and natural gas proceeds | 21,390 | 1,259 | — | — | 22,649 |
| Asset retirement obligations | 21,663 | 6,260 | — | — | 27,923 |
| Current maturities of long-term debt: | | | | | |
| Principal | 189,829 | — | — | — | 189,829 |
| Carrying value adjustments | 34,917 | — | — | — | 34,917 |
| Current maturities of long-term debt - carrying value | 224,746 | — | — | — | 224,746 |
| Accrued liabilities | 20,523 | 128,336 | — | (128,354) | 20,505 |
| Total current liabilities | 326,767 | 142,312 | 1,562 | (128,354) | 342,287 |
| Long-term debt: | | | | | |
| Principal | 713,365 | — | — | — | 713,365 |
| Carrying value adjustments | 47,605 | — | — | — | 47,605 |
| Long term debt, less current portion - carrying value | 760,970 | — | — | — | 760,970 |
| | | | | | |
| Asset retirement obligations, less current portion | 164,010 | 125,275 | 12 | — | 289,297 |
| Other liabilities | 663,239 | — | — | (590,232) | 73,007 |
| | | | | | |
| Shareholders' deficit: | | | | | |
| Common stock | 1 | — | — | — | 1 |
| Additional paid-in capital | 548,196 | 704,885 | — | (704,885) | 548,196 |
| Retained earnings (deficit) | (1,021,694) | (259,507) | (201) | 249,963 | (1,031,439) |
| Treasury stock, at cost | (24,167) | — | — | — | (24,167) |
| Total shareholders' equity (deficit) | (497,664) | 445,378 | (201) | (454,922) | (507,409) |
| Total liabilities and shareholders' equity (deficit) | $ 1,417,322 | $ 712,965 | $ 1,373 | $ (1,173,508) | $ 958,152 |

**Condensed Consolidating Balance Sheet as of December 31, 2017**

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | (In thousands) | | | |
| **Assets** | | | | |
| Current assets: | | | | |
| Cash and cash equivalents | $ 99,058 | $ — | $ — | $ 99,058 |
| Receivables: | | | | |
| Oil and natural gas sales | 5,665 | 39,778 | — | 45,443 |
| Joint interest | 19,754 | — | — | 19,754 |
| Income taxes | 128,835 | — | (115,829) | 13,006 |
| Total receivables | 154,254 | 39,778 | (115,829) | 78,203 |
| Prepaid expenses and other assets | 11,154 | 2,265 | — | 13,419 |
| Total current assets | 264,466 | 42,043 | (115,829) | 190,680 |
| Oil and natural gas properties and other, net | 430,354 | 152,464 | (3,802) | 579,016 |
| Restricted deposits for asset retirement obligations | 25,394 | — | — | 25,394 |
| Income taxes receivable | 52,097 | — | — | 52,097 |
| Other assets | 505,304 | 453,306 | (898,217) | 60,393 |
| Total assets | $ 1,277,615 | $ 647,813 | $ (1,017,848) | $ 907,580 |
| **Liabilities and Shareholders' Deficit** | | | | |
| Current liabilities: | | | | |
| Accounts payable | $ 76,703 | $ 6,962 | $ — | $ 83,665 |
| Undistributed oil and natural gas proceeds | 18,762 | 1,367 | — | 20,129 |
| Asset retirement obligations | 22,488 | 1,125 | — | 23,613 |
| Current maturities of long-term debt - carrying value | 22,925 | — | — | 22,925 |
| Accrued liabilities | 18,058 | 115,701 | (115,829) | 17,930 |
| Total current liabilities | 158,936 | 125,155 | (115,829) | 168,262 |
| Long-term debt: | | | | |
| Principal | 889,790 | — | — | 889,790 |
| Carrying value adjustments | 79,337 | — | — | 79,337 |
| Long term debt, less current portion - carrying value | 969,127 | — | — | 969,127 |
| Asset retirement obligations, less current portion | 152,883 | 123,950 | — | 276,833 |
| Other liabilities | 566,375 | — | (499,509) | 66,866 |
| Shareholders' deficit: | | | | |
| Common stock | 1 | — | — | 1 |
| Additional paid-in capital | 545,820 | 704,885 | (704,885) | 545,820 |
| Retained earnings (deficit) | (1,091,360) | (306,177) | 302,375 | (1,095,162) |
| Treasury stock, at cost | (24,167) | — | — | (24,167) |
| Total shareholders' deficit | (569,706) | 398,708 | (402,510) | (573,508) |
| Total liabilities and shareholders' deficit | $ 1,277,615 | $ 647,813 | $ (1,017,848) | $ 907,580 |

**Condensed Consolidating Statement of Operations for the Three Months Ended June 30, 2018**

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Adjustments | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| Revenues | $ 77,270 | $ 71,873 | $ 469 | $ — | $ 149,612 |
| Operating costs and expenses: | | | | | |
| Lease operating expenses | 21,617 | 13,929 | 36 | — | 35,582 |
| Production taxes | 439 | — | — | — | 439 |
| Gathering and transportation | 2,834 | 2,084 | 10 | — | 4,928 |
| Depreciation, depletion, amortization and accretion | 19,954 | 16,743 | 164 | 2,896 | 39,757 |
| General and administrative expenses | 6,854 | 7,166 | 200 | — | 14,220 |
| Derivative gain | 6,219 | — | — | — | 6,219 |
| Total costs and expenses | 57,917 | 39,922 | 410 | 2,896 | 101,145 |
| Operating income | 19,353 | 31,951 | 59 | (2,896) | 48,467 |
| Earnings of affiliates | 24,502 | — | — | (24,502) | — |
| Interest expense | 12,147 | — | — | — | 12,147 |
| Other (income) expense, net | (121) | — | 246 | — | 125 |
| Income before income tax expense (benefit) | 31,829 | 31,951 | (187) | (27,398) | 36,195 |
| Income tax expense (benefit) | (7,337) | 7,449 | — | — | 112 |
| Net income | $ 39,166 | $ 24,502 | $ (187) | $ (27,398) | $ 36,083 |

**Condensed Consolidating Statement of Operations for the Six Months Ended June 30, 2018**

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Adjustments | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| Revenues | $ 141,056 | $ 142,300 | $ 469 | $ — | $ 283,825 |
| Operating costs and expenses: | | | | | |
| Lease operating expenses | 41,377 | 31,012 | 36 | — | 72,425 |
| Production taxes | 894 | — | — | — | 894 |
| Gathering and transportation | 5,537 | 4,438 | 10 | — | 9,985 |
| Depreciation, depletion, amortization and accretion | 39,374 | 32,557 | 164 | 5,743 | 77,838 |
| General and administrative expenses | 14,057 | 14,990 | 211 | — | 29,258 |
| Derivative gain | 6,219 | — | — | — | 6,219 |
| Total costs and expenses | 107,458 | 82,997 | 421 | 5,743 | 196,619 |
| Operating income | 33,598 | 59,303 | 48 | (5,743) | 87,206 |
| Earnings of affiliates | 46,669 | — | — | (46,669) | — |
| Interest expense | 23,470 | — | — | — | 23,470 |
| Other (income) expense, net | (457) | — | 249 | — | (208) |
| Income before income tax expense (benefit) | 57,254 | 59,303 | (201) | (52,412) | 63,944 |
| Income tax expense (benefit) | (12,413) | 12,634 | — | — | 221 |
| Net income | $ 69,667 | $ 46,669 | $ (201) | $ (52,412) | $ 63,723 |

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

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | (In thousands) | | | |
| Revenues | $ 57,417 | $ 65,906 | $ — | $ 123,323 |
| Operating costs and expenses: | | | | |
| Lease operating expenses | 17,325 | 14,194 | — | 31,519 |
| Production taxes | 449 | — | — | 449 |
| Gathering and transportation | 2,578 | 2,740 | — | 5,318 |
| Depreciation, depletion, amortization and accretion | 21,433 | 18,143 | 788 | 40,364 |
| General and administrative expenses | 7,662 | 8,812 | — | 16,474 |
| Derivative gain | (3,689) | — | — | (3,689) |
| Total costs and expenses | 45,758 | 43,889 | 788 | 90,435 |
| Operating income | 11,659 | 22,017 | (788) | 32,888 |
| Earnings of affiliates | 18,941 | — | (18,941) | — |
| Interest expense | 11,436 | — | — | 11,436 |
| Gain on exchange of debt | 8,056 | — | — | 8,056 |
| Other expense, net | 5,168 | — | — | 5,168 |
| Income before income tax expense (benefit) | 22,052 | 22,017 | (19,729) | 24,340 |
| Income tax expense (benefit) | (12,051) | 3,076 | — | (8,975) |
| Net income | $ 34,103 | $ 18,941 | $ (19,729) | $ 33,315 |

**Condensed Consolidating Statement of Operations for the Six Months Ended June 30, 2017**

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | (In thousands) | | | |
| Revenues | $ 111,124 | $ 136,592 | $ — | $ 247,716 |
| Operating costs and expenses: | | | | |
| Lease operating expenses | 41,027 | 30,656 | — | 71,683 |
| Production taxes | 964 | — | — | 964 |
| Gathering and transportation | 5,144 | 6,383 | — | 11,527 |
| Depreciation, depletion, amortization and accretion | 40,587 | 38,248 | 1,519 | 80,354 |
| General and administrative expenses | 13,438 | 16,310 | — | 29,748 |
| Derivative gain | (7,644) | — | — | (7,644) |
| Total costs and expenses | 93,516 | 91,597 | 1,519 | 186,632 |
| Operating income | 17,608 | 44,995 | (1,519) | 61,084 |
| Earnings of affiliates | 36,468 | — | (36,468) | — |
| Interest expense | 22,730 | — | — | 22,730 |
| Gain on exchange of debt | 7,811 | — | — | 7,811 |
| Other expense, net | 5,114 | — | — | 5,114 |
| Income before income tax expense (benefit) | 34,043 | 44,995 | (37,987) | 41,051 |
| Income tax expense (benefit) | (25,090) | 8,527 | — | (16,563) |
| Net loss | $ 59,133 | $ 36,468 | $ (37,987) | $ 57,614 |

**Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2018**

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Adjustments | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Operating activities:** | | | | | |
| Net income | $ 69,667 | $ 46,669 | $ (201) | $ (52,412) | $ 63,723 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | | | |
| Depreciation, depletion, amortization and accretion | 39,374 | 32,557 | 164 | 5,743 | 77,838 |
| Amortization of debt items and other items | 1,126 | — | — | — | 1,126 |
| Share-based compensation | 2,434 | — | — | — | 2,434 |
| Derivative loss | 6,219 | — | — | — | 6,219 |
| Cash receipts on derivative settlements, net | (1,149) | — | — | — | (1,149) |
| Deferred income taxes | 221 | — | — | — | 221 |
| Earnings of affiliates | (46,669) | — | — | 46,669 | — |
| Changes in operating assets and liabilities: | | | | — | |
| Oil and natural gas receivables | (2,444) | (4,383) | 197 | — | (6,630) |
| Joint interest receivables | 251 | — | — | — | 251 |
| Income taxes | (12,772) | 12,634 | — | — | (138) |
| Prepaid expenses and other assets | (37,025) | (72,465) | 4,445 | 90,722 | (14,323) |
| Asset retirement obligation settlements | (7,725) | (4,399) | — | — | (12,124) |
| Accounts payable, accrued liabilities and other | 80,147 | 8,055 | 264 | (90,722) | (2,256) |
| Net cash provided by operating activities | 91,655 | 18,668 | 4,869 | — | 115,192 |
| **Investing activities:** | | | | | |
| Investment in oil and natural gas properties and equipment | (15,638) | (9,999) | (6,166) | — | (31,803) |
| Changes in operating assets and liabilities associated with investing activities | (21,958) | (8,669) | 1,297 | — | (29,330) |
| Acquisition of property interest | (16,617) | — | — | — | (16,617) |
| Net cash used in investing activities | (54,213) | (18,668) | (4,869) | — | (77,750) |
| **Financing activities:** | | | | | |
| Payment of interest on 1.5 Lien Term Loan | (4,114) | — | — | — | (4,114) |
| Payment of interest on 2nd Lien PIK Toggle Notes | (2,920) | — | — | — | (2,920) |
| Other | (26) | — | — | — | (26) |
| Net cash used in financing activities | (7,060) | — | — | — | (7,060) |
| Increase in cash and cash equivalents | 30,382 | — | — | — | 30,382 |
| Cash and cash equivalents, beginning of period | 99,058 | — | — | — | 99,058 |
| Cash and cash equivalents, end of period | $ 129,440 | $ — | $ — | $ — | $ 129,440 |

**Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2017**

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | (In thousands) | | | |
| **Operating activities:** | | | | |
| Net income | $ 59,133 | $ 36,468 | $ (37,987) | $ 57,614 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | | |
| Depreciation, depletion, amortization and accretion | 40,587 | 38,248 | 1,519 | 80,354 |
| Gain on exchange of debt | (7,811) | — | — | (7,811) |
| Amortization of debt items | 836 | — | — | 836 |
| Share-based compensation | 3,466 | — | — | 3,466 |
| Derivative gain | (7,644) | — | — | (7,644) |
| Cash receipts on derivative settlements | 2,208 | — | — | 2,208 |
| Deferred income taxes | 212 | — | — | 212 |
| Earnings of affiliates | (36,468) | — | 36,468 | — |
| Changes in operating assets and liabilities: | | | | |
| Oil and natural gas receivables | (1,095) | 4,770 | — | 3,675 |
| Joint interest receivables | 1,965 | — | — | 1,965 |
| Insurance reimbursements | 30,100 | — | — | 30,100 |
| Income taxes | (25,487) | 8,527 | — | (16,960) |
| Prepaid expenses and other assets | (3,165) | (74,591) | 74,181 | (3,575) |
| Escrow deposit - Apache lawsuit | (49,500) | — | — | (49,500) |
| Asset retirement obligations | (25,044) | (10,977) | — | (36,021) |
| Accounts payable, accrued liabilities and other | 81,785 | (938) | (74,181) | 6,666 |
| Net cash provided by operating activities | 64,078 | 1,507 | — | 65,585 |
| **Investing activities:** | | | | |
| Investment in oil and natural gas properties and equipment | (41,854) | (1,946) | — | (43,800) |
| Changes in operating assets and liabilities associated with investing activities | (1,266) | 439 | — | (827) |
| Purchases of furniture, fixtures and other | (853) | — | — | (853) |
| Net cash used in investing activities | (43,973) | (1,507) | — | (45,480) |
| **Financing activities:** | | | | |
| Payment of interest on 1.5 Lien Term Loan | (4,113) | — | — | (4,113) |
| 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) |
| Other | (372) | — | — | (372) |
| Net cash used in financing activities | (18,021) | — | — | (18,021) |
| Increase in cash, cash equivalents and restricted cash | 2,084 | — | — | 2,084 |
| Cash and cash equivalents, beginning of period | 70,236 | — | — | 70,236 |
| Cash and cash equivalents, end of period | $ 72,320 | $ — | $ — | $ 72,320 |

## 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, 2017 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 48 offshore producing fields in federal and state waters (45 producing and three fields capable of producing). We currently have under lease approximately 650,000 gross acres, with approximately 440,000 gross acres on the shelf and approximately 210,000 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, and by Monza Energy LLC ("Monza"), which we proportionately consolidate in our condensed consolidated financial statements.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our crude oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for the six months ended June 30, 2018 were comprised of 48.8% crude oil and condensate, 9.9% NGLs and 41.3% 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 barrel of equivalent ("Boe") for crude oil, NGLs and natural gas has differed significantly in the past. For the six months ended June 30, 2018, revenues from the sale of crude oil and NGLs made up 81.9% of our total revenues compared to 75.2% for the six months ended June 30, 2017. For the six months ended June 30, 2018, our combined total production expressed in equivalent volumes was 13.1% lower than for the six months ended June 30, 2017, with natural gas having the largest decline. For the six months ended June 30, 2018, our total revenues were 14.6% higher than the six months ended June 30, 2017 due to significantly higher realized prices for crude oil and NGLs. See *Results of Operations – Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017* in this Item 2 for additional information.

On March 12, 2018, W&T and two other initial members formed and initially funded a limited liability company, Monza, that will jointly participate with us in the exploration, drilling and development of up to 14 identified drilling projects in the Gulf of Mexico over the next three years. We refer to these projects herein as the JV Drilling Program. W&T initially contributed 88.94% of its working interest in 14 identified undeveloped drilling projects to Monza and retained 11.06% of its working interest. The Monza board has approved the substitution of one of these identified undeveloped drilling projects, the VK823 A-14 well, with the VK823 A-13 well, which is in the process of being contributed to Monza through the conveyance by W&T of 58.71% of its working interest in such well to Monza and retaining 41.29% of its working interest in such well. The interest in the VK823 A-14 well will be reconveyed to W&T. Since the initial closing, additional investors have joined as members of Monza and as of June 30, 2018, total commitments by all members, including W&T, are $361.4 million. Monza has closed off funding from additional investors. The JV Drilling Program is structured so that we initially receive an aggregate of 30.0% of the revenues less expenses, through both our direct ownership of our working interest in the projects and our indirect interest through our interest in Monza, for contributing 20.0% of the estimated total well costs plus associated leases and providing access to available infrastructure at agreed upon rates. See *Financial Statements – Note 4 – JV Drilling Program* under Part I, Item 1 of this Form 10-Q for additional information.

On April 5, 2018, we closed on the purchase from Cobalt International Energy, Inc. of a 9.375% non-operated working interest in the Heidelberg field located in Green Canyon blocks 859, 903 and 904. The gross purchase price was $31.1 million which was adjusted for certain closing items and an effective date of January 1, 2018. Cash flows generated by the acquired interest between the effective date and the closing date reduced the net purchase price to $16.6 million on the closing date. We were required to furnish a letter of credit in the amount of $9.4 million to a pipeline company as consignee. In addition, we recognized ARO of $3.6 million as a component of the transaction.

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 six months ended June 30, 2018, our average realized crude oil price was $64.93 per barrel. This is an increase over our average realized crude oil price of $45.76 per barrel for the six months ended June 30, 2017 and an increase over our average realized crude oil price of $48.13 per barrel for the year 2017. In addition, average realized prices of NGLs for the six months ended June 30, 2018 were higher than average realized prices for the six months ended June 30, 2017 and the year 2017.

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

As reported by the U.S. Energy Information Administration ("EIA") in their Short-Term Energy Outlook issued in July 2018 ("STEO"), the overall crude oil and other petroleum liquids market for the three months ended June 30, 2018 had an inventory build, which reversed the trend of inventory draws during each of the quarters during 2017 and the first quarter of 2018. But, the inventory build did not appear to negatively affect crude oil prices, as both WTI and Brent average crude oil prices increased during the second quarter as compared to the first quarter of 2018. EIA forecasts inventories to be drawn down slightly in the third quarter of 2018, then having inventory builds in the fourth quarter of 2018 and each of the quarters of 2019.

The EIA reported worldwide total crude oil and petroleum liquids inventories increased in the second quarter of 2018 by 0.6 million barrels per day. For the countries grouped by EIA in the category of Organization for Economic Cooperation and Development ("OECD"), second quarter 2018 crude oil inventories were 4% above the five-year average, but on a days-of-supply basis, OECD crude oil inventories for the second quarter of 2018 were below the 5-year average by 1%. EIA forecasts OECD crude oil inventories to remain fairly constant through the end of 2018 as compared to 2017 level, but rising by 5% during 2019 as compared to 2018. Increased production is the driving factor for the forecasted inventory build.

The EIA forecasts an increase in worldwide production for the second half of 2018 compared to the first half of 2018 by 1.5% due primarily to increases in production in the U.S., Canada and Brazil. For the year 2018, the EIA estimates worldwide crude oil and petroleum liquids production to be 100.15 million barrels per day, an increase of 2.2% over 2017. Consumption for 2018 is estimated to be 100.20 million barrels per day, an increase of 1.7% over 2017, with China and other Asian countries being the primary contributors to the increase in consumption.

According to EIA's STEO, 2018 U.S. crude oil production (excluding other petroleum liquids) is expected to increase by 15% over 2017 and increase by 9% in 2019 over 2018 levels. If EIA's forecast is achieved in each year, crude oil production in the U.S will be at the highest level in recorded history, surpassing the current record set in 1970. In addition, if these production levels are achieved, this would make the U.S. the largest producer in the world for these years. These production levels have pushed pipeline capacities to the maximum levels in the Permian Basin, which may limit short-term growth until pipeline capacity can be increased. Net imports of crude oil in the U.S. are expected to decrease by 12% in 2018 compared to 2017 and further decrease by 13% in 2019 compared to 2018. As noted below, the number of onshore rigs drilling for oil has increased from 2017 levels.

Geopolitical events could greatly affect the prices for crude oil, natural gas and other petroleum products. While these events are difficult to predict, countries like Venezuela, Nigeria, Libya, and many Middle East countries have had, and could continue to have, disruptions due to political and economic factors outside of production issues.

During the six months ended June 30, 2018, our average realized crude oil sales price was $64.93 per barrel, up from $45.76 per barrel (41.9% higher) for the six months ended June 30, 2017. The two primary benchmarks are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $65.55 per barrel for the six months ended June 30, 2018, up from $49.85 per barrel (31.5% higher) for the six months ended June 30, 2017. Brent crude oil prices averaged $70.67 per barrel for the six months ended June 30, 2018, up from $51.57 per barrel (37.0% higher) for the six months ended June 30, 2017. The rising U.S. crude oil production put upward price pressure on the Brent-to-WTI premium, which increased 211% to an average of $5.19 per barrel for the six months ended June 30, 2018 compared to an average of $1.67 per barrel for the six months ended June 30, 2017.

For the six months ended June 30, 2018, our average realized crude oil sales price was $64.93 per barrel compared to a WTI benchmark price of $65.55 per barrel. Our average realized crude oil sales price differs from the benchmark crude prices due to premiums or discounts, crude oil quality adjustments, volume weighting (collectively referred to as differentials) and other factors. Crude oil quality adjustments can vary significantly by field. For example, crude oil from our East Cameron 321 field normally receives a positive quality adjustment, whereas crude oil from our Ship Shoal 349 field ("Mahogany") normally receives a negative quality adjustment. All of our crude oil is 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 crude 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 six months ended June 30, 2018 improved by approximately $2.00 per barrel compared to the six months ended June 30, 2017 for these types of crude oils.

Despite the projection by the EIA that crude oil inventories will remain fairly level on an end-of-year comparison for 2018 to 2017, the EIA projects average crude oil prices for both WTI and Brent to increase by approximately $15.00 to $17.00 per barrel, respectively, for the year 2018 compared to 2017. EIA's forecast of crude oil prices for both WTI and Brent are expected to decrease by approximately $3.00 per barrel for the year 2019 compared to 2018. Per the EIA, economic and political instability in Venezuela continues to negatively affect its crude oil production. Uncertainty remains regarding the effect of U.S. sanctions on Iran and the degree to which the sanctions will take crude oil off the market. These factors may have impacted crude oil prices, but other unidentified factors may also be affecting the market as these alone do not seem to account for the increase in 2018 given that supply is expected to be approximately equal to consumption.

During the six months ended June 30, 2018, our average realized NGLs sales price increased by 26.5% compared to the six months ended June 30, 2017. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the six months ended June 30, 2018, average prices for domestic ethane increased by 10% and average domestic propane prices increased by 28% from the six months ended June 30, 2017. Average price changes for other domestic NGLs were an increase of 11% to 36% between the two periods. We believe the increase in prices for NGLs is mostly a function of the change in crude oil prices and propane usage during the recent winter season. Per EIA, production of ethane is expected to increase by 23% in 2018 compared to 2017 and increase by 12% in 2019 compared to 2018. Propane production is expected to increase by 13% in 2018 compared to 2017 and by 9% in 2019 compared to 2018. Ethane inventories decreased 7% as of June 2018 compared to June 2017. Ethane usage is not impacted by weather, but primarily by demand from petrochemical plants. Additional ethane steam crackers coming on line is impacting the usage of ethane, which is believed to positively impact the price. 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 2%

higher at the end of the second quarter of 2018 compared to the same period last year. Heating degree days were 16% higher in the first half of 2018 compared to the same period last year.

During the six months ended June 30, 2018, our average realized natural gas sales price decreased 1.7% compared to the six months ended June 30, 2017. According to data from EIA's web site, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 4.9% lower in the six months ended June 30, 2018 compared to the six months ended June 30, 2017. 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 inventories at the end of the second quarter of 2018 were 25% lower than the prior year period and were 17% below the five-year average for the previous five years.

Despite good demand for natural gas, the average price of natural gas continues to be weak from an overall economic standpoint as to making an adequate rate of return on wells that produce only natural gas. The forward price curve that goes out several years shows natural gas prices well below $3.00 per Mcf. Accordingly, the market expects 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 and (iv) re-injecting ethane from time to time into the natural gas stream, which increases the natural gas supply.

EIA projects natural gas prices to be flat in 2018 compared to 2017 and to increase 2% in 2019 compared to 2018. U.S. supply is projected to be slightly higher than consumption in 2018 and 2019, resulting in minor inventory builds. EIA's forecast of fuel used for electrical power generation has natural gas consumption increasing in 2018 to 34% from 32% in 2017. Electrical power generation from coal is forecast to decrease to 28% in 2018 from 30% in 2017. Electrical power from renewable sources such as hydropower and wind is expected to be 17% in both 2018 and 2017.

As of June 30, 2018, the number of working rigs drilling for oil and natural gas in the U.S. was higher than year ago levels for land based rigs (109 rigs, or 12%), but lower in offshore waters (two rigs or 10%). According to Baker Hughes, the oil rig count at the end of June 2018, December 2017 and June 2017 was 858, 747 and 756, respectively. The U.S. natural gas rig count at the end of June 2018, December 2017 and June 2017 was 187, 182 and 184, respectively. In the Gulf of Mexico, the number of working rigs was 18 rigs (15 oil and three natural gas) at the end of June 2018; 18 rigs (14 oil and four natural gas) at the end of December 2017; and 21 rigs (18 oil and three natural gas) at the end of June 2017.

Our current 2018 capital expenditure forecast for 2018 is approximately $95 million, which excludes the Heidelberg field transaction and excludes other potential acquisitions. The forecast also incorporates the JV Drilling Program. Our 2018 capital expenditure program includes participation in 10 wells, seven of which are included in the 2018 JV Drilling Program.

We expect to be able to address the upcoming maturities of our debt instruments, have adequate cash balances and have no draws on our revolving bank credit facility during 2018. See the *Liquidity and Capital Resources* section of this Item 2 for a discussion of our financing plans. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments.

Our short term focus is on liquidity, cost reductions, fulfilling our obligations and making investments with short payback time frames. 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, 2017, 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 June 30, | | | | Six Months Ended June 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| | (In thousands, except percentages and per share data) | | | | | | | |
| **Financial:** | | | | | | | | |
| Revenues: | | | | | | | | |
| Oil | $ 116,618 | $ 85,622 | $ 30,996 | 36.2 % | $ 213,924 | $ 170,593 | $ 43,331 | 25.4 % |
| NGLs | 8,734 | 7,054 | 1,680 | 23.8 % | 18,394 | 15,796 | 2,598 | 16.4 % |
| Natural gas | 22,977 | 29,258 | (6,281 ) | (21.5 )% | 48,844 | 59,016 | (10,172 ) | (17.2 )% |
| Other | 1,283 | 1,389 | (106 ) | (7.6 )% | 2,663 | 2,311 | 352 | 15.2 % |
| Total revenues | 149,612 | 123,323 | 26,289 | 21.3 % | 283,825 | 247,716 | 36,109 | 14.6 % |
| Operating costs and expenses: | | | | | | | | |
| Lease operating expenses | 35,582 | 31,519 | 4,063 | 12.9 % | 72,425 | 71,683 | 742 | 1.0 % |
| Production taxes | 439 | 449 | (10 ) | (2.2 )% | 894 | 964 | (70 ) | (7.3 )% |
| Gathering and transportation | 4,928 | 5,318 | (390 ) | (7.3 )% | 9,985 | 11,527 | (1,542 ) | (13.4 )% |
| Depreciation, depletion, amortization and accretion | 39,757 | 40,364 | (607 ) | (1.5 )% | 77,838 | 80,354 | (2,516 ) | (3.1 )% |
| General and administrative expenses | 14,220 | 16,474 | (2,254 ) | (13.7 )% | 29,258 | 29,748 | (490 ) | (1.6 )% |
| Derivative (gain) loss | 6,219 | (3,689 ) | 9,908 | NM | 6,219 | (7,644 ) | 13,863 | NM |
| Total costs and expenses | 101,145 | 90,435 | 10,710 | 11.8 % | 196,619 | 186,632 | 9,987 | 5.4 % |
| Operating income | 48,467 | 32,888 | 15,579 | 47.4 % | 87,206 | 61,084 | 26,122 | 42.8 % |
| Interest expense | 12,147 | 11,436 | 711 | 6.2 % | 23,470 | 22,730 | 740 | 3.3 % |
| Gain on exchange of debt | — | 8,056 | (8,056 ) | NM | — | 7,811 | (7,811 ) | NM |
| Other (income) expense, net | 125 | 5,168 | (5,043 ) | NM | (208 ) | 5,114 | (5,322 ) | NM |
| Income before income tax expense (benefit) | 36,195 | 24,340 | 11,855 | 48.7 % | 63,944 | 41,051 | 22,893 | 55.8 % |
| Income tax expense (benefit) | 112 | (8,975 ) | 9,087 | NM | 221 | (16,563 ) | 16,784 | NM |
| Net income | $ 36,083 | $ 33,315 | $ 2,768 | 8.3 % | $ 63,723 | $ 57,614 | $ 6,109 | 10.6 % |
| Basic and diluted earnings per common share | $ 0.25 | $ 0.23 | $ 0.02 | 8.7 % | $ 0.44 | $ 0.40 | $ 0.04 | 10.0 % |

NM – not meaningful

| | Three Months Ended June 30, 2018 | Three Months Ended June 30, 2017 | Change | % (2) | Six Months Ended June 30, 2018 | Six Months Ended June 30, 2017 | Change | % (2) |
|---|---|---|---|---|---|---|---|---|
| **Operating: (1)** | | | | | | | | |
| Net sales: | | | | | | | | |
| Oil (MBbls) | 1,738 | 1,923 | (185) | (9.6)% | 3,295 | 3,728 | (433) | (11.6)% |
| NGLs (MBbls) | 316 | 351 | (35) | (10.0)% | 667 | 725 | (58) | (8.0)% |
| Natural gas (MMcf) | 8,186 | 9,890 | (1,704) | (17.2)% | 16,709 | 19,875 | (3,166) | (15.9)% |
| Total oil equivalent (MBoe) | 3,419 | 3,921 | (502) | (12.8)% | 6,747 | 7,765 | (1,018) | (13.1)% |
| Total nat. gas equiv. (MMcfe) | 20,514 | 23,524 | (3,010) | (12.8)% | 40,481 | 46,589 | (6,108) | (13.1)% |
| Avg. daily equivalent sales (Boe/day) | 37,571 | 43,084 | (5,513) | (12.8)% | 37,275 | 42,899 | (5,624) | (13.1)% |
| Avg. daily equiv. sales (Mcfe/day) | 225,427 | 258,503 | (33,076) | (12.8)% | 223,650 | 257,395 | (33,745) | (13.1)% |
| Average realized sales prices: | | | | | | | | |
| Oil ($/Bbl) | $ 67.09 | $ 44.54 | $ 22.55 | 50.6% | $ 64.93 | $ 45.76 | $ 19.17 | 41.9% |
| NGLs ($/Bbl) | 27.61 | 20.15 | 7.46 | 37.0% | 27.57 | 21.80 | 5.77 | 26.5% |
| Natural gas ($/Mcf) | 2.81 | 2.96 | (0.15) | (5.1)% | 2.92 | 2.97 | (0.05) | (1.7)% |
| Oil equivalent ($/Boe) | 43.38 | 31.10 | 12.28 | 39.5% | 41.67 | 31.61 | 10.06 | 31.9% |
| Natural gas equivalent ($/Mcfe) | 7.23 | 5.18 | 2.05 | 39.6% | 6.95 | 5.27 | 1.68 | 31.8% |
| Average per Boe ($/Boe): | | | | | | | | |
| Lease operating expenses | $ 10.41 | $ 8.04 | $ 2.37 | 29.5% | $ 10.73 | $ 9.23 | $ 1.50 | 16.3% |
| Gathering and transportation | 1.44 | 1.36 | 0.08 | 5.9% | 1.48 | 1.48 | — | — |
| Production costs | 11.85 | 9.40 | 2.45 | 26.1% | 12.21 | 10.71 | 1.50 | 14.0% |
| Production taxes | 0.13 | 0.11 | 0.02 | 18.2% | 0.13 | 0.12 | 0.01 | 8.3% |
| DD&A | 11.63 | 10.29 | 1.34 | 13.0% | 11.54 | 10.35 | 1.19 | 11.5% |
| G&A expenses | 4.16 | 4.20 | (0.04) | (1.0)% | 4.34 | 3.83 | 0.51 | 13.3% |
| | $ 27.77 | $ 24.00 | $ 3.77 | 15.7% | $ 28.22 | $ 25.01 | $ 3.21 | 12.8% |
| Average per Mcfe ($/Mcfe): | | | | | | | | |
| Lease operating expenses | $ 1.73 | $ 1.34 | $ 0.39 | 29.1% | $ 1.79 | $ 1.54 | $ 0.25 | 16.2% |
| Gathering and transportation | 0.24 | 0.23 | 0.01 | 4.3% | 0.25 | 0.25 | — | — |
| Production costs | 1.97 | 1.57 | 0.40 | 25.5% | 2.04 | 1.79 | 0.25 | 14.0% |
| Production taxes | 0.02 | 0.02 | — | — | 0.02 | 0.02 | — | — |
| DD&A | 1.94 | 1.72 | 0.22 | 12.8% | 1.92 | 1.72 | 0.20 | 11.6% |
| G&A expenses | 0.69 | 0.70 | (0.01) | (1.4)% | 0.72 | 0.64 | 0.08 | 12.5% |
| | $ 4.62 | $ 4.01 | $ 0.61 | 15.2% | $ 4.70 | $ 4.17 | $ 0.53 | 12.7% |

(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 crude 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 June 30, 2018 Compared to the Three Months Ended June 30, 2017***

*Revenues*. Total revenues increased $26.3 million, or 21.3%, to $149.6 million for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017. Oil revenues increased $31.0 million, or 36.2%, NGLs revenues increased $1.7 million, or 23.8%, natural gas revenues decreased $6.3 million, or 21.5%, and other revenues decreased $0.1 million. The increase in oil revenues was attributable to a 50.6% increase in the average realized sales price to $67.09 per barrel for the three months ended June 30, 2018 from $44.54 per barrel for the three months ended June 30, 2017, partially offset by a decrease in sales volumes of 9.6%. The increase in NGLs revenues was attributable to a 37.0% increase in the average realized sales price to $27.61 per barrel for the three months ended June 30, 2018 from $20.15 per barrel for the three months ended June 30, 2017, partially offset by a decrease in sales volumes of 10.0%. The decrease in natural gas revenues was attributable to a decrease in sales volumes of 1.7 billion cubic feet ("Bcf"), or 17.2% and a 5.1% decrease in the average realized price to $2.81 per Mcf for the three months ended June 30, 2018 from $2.96 per Mcf for the three months ended June 30, 2017. Overall, production volumes decreased 12.8% on a Boe basis. The largest production increases for the three months ended June 30, 2018 compared to the three months ended June 30, 2017 were from our newly acquired interest in the Heidelberg field and our Ship Shoal 300 field. Offsetting were production decreases primarily due to natural production declines. Production for the three months ended June 30, 2018 was also negatively impacted by maintenance, well issues and pipeline outages that collectively resulted in deferred production of 4,600 Boe per day. During the three months ended June 30, 2017, deferred production was 3,400 Boe per day.

Revenues from oil and NGLs as a percent of our total revenues were 83.8% for the three months ended June 30, 2018 compared to 75.1% for the three months ended June 30, 2017. Our average realized NGLs sales price as a percent of our average realized crude oil sales price decreased to 41.1% for the three months ended June 30, 2018 compared to 45.2% for the three months ended June 30, 2017.

*Lease operating expenses.* Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, increased $4.1 million, or 12.9%, to $35.6 million in the three months ended June 30, 2018 compared to the three months ended June 30, 2017. On a component basis, base lease operating expenses increased $3.1 million, facilities maintenance expense increased $0.7, insurance premiums increased $0.5 million and workover expenses decreased $0.2 million. Base lease operating expenses increased primarily due to the addition of the Heidelberg field; lower product handling and operating charges to an outside party at our Mississippi Canyon 243 field (Matterhorn) and higher charges from non-operated properties. (Compared to the three months ended March 31, 2018, base lease operating expense decreased $1.2 million.) The facility maintenance expense increase was primarily attributable to a pipeline repair at our East Cameron 321 field. The insurance premium increase is primarily due to our insurance policies related to named windstorms, which had better coverage between the two periods. The decrease in workover expense was primarily due to a 2017 project at the Brazos Area 133 field, partially offset by a 2018 project at our Mahogany field.

*Production taxes.* Production taxes were basically flat for the three months ended June 30, 2018 compared to the three months ended June 30, 2017. 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 $0.4 million to $4.9 million for the three months ended June 30, 2018 compared to the three months ended June 30, 2017 primarily due to lower production volumes of all of the commodities we produce.

*Depreciation, depletion, amortization and accretion ("DD&A").* DD&A, which includes accretion for ARO, increased to $11.63 per Boe for the three months ended June 30, 2018 from $10.29 per Boe for the three months ended June 30, 2017. On a nominal basis, DD&A decreased to $39.8 million (or 1.5%) for the three months ended June 30, 2018 from $40.4 million for the three months ended June 30, 2017. DD&A on a nominal basis decreased primarily due to lower production. Other factors affecting the DD&A rate are capital expenditures, changes in future development costs on remaining reserves and an increase in proved reserves volumes.

*General and administrative expenses ("G&A")*. G&A was $14.2 million for the three months ended June 30, 2018, decreasing 13.7% from $16.5 million for the three months ended June 30, 2017. The decrease was primarily due to decreases in share-based compensation as there have been no RSU grants in 2018 and in lower legal costs. G&A on a per Boe basis was $4.16 per Boe for the three months ended June 30, 2018 compared to $4.20 per Boe for the three months ended June 30, 2017.

*Derivative (gain) loss.* We entered into derivative contracts for crude oil during the second quarter of 2018 relating to a portion of our 2018 estimated production. The three months ended June 30, 2018 reflects a $6.2 million derivative loss. 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 three months ended June 30, 2017 reflects a $3.7 million derivative gain primarily for our crude oil derivative contracts.

*Interest expense*. Interest expense was $12.1 million and $11.4 million for the three months ended June 30, 2018 and 2017, respectively. The increase is primarily due to an interest accrual related to a royalty issue with the ONRR on production that dates back 10 to 15 years. *See Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information on our debt.

*Gain on exchange of debt*. For the three months ended June 30, 2017, an additional net gain of $8.1 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 the 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.

*Other (income) expense, net*. During the three months ended June 30, 2017, other expense, net, was $5.2 million and 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 11– Contingencies* under Part I, Item 1 of this Form 10-Q for additional information on the Apache lawsuit.

*Income tax expense (benefit).* Our income tax expense for the three months ended June 30, 2018 was $0.1 million and our income tax benefit for the three months ended June 30, 2017 was $9.0 million. Our current full-year forecast for 2018 has a net operating loss for tax purposes; therefore, no current tax expense was recorded related to the full-year forecast. No deferred income tax expense was recorded for the three months ended June 30, 2018 due to dollar-for-dollar offsets by our valuation allowance. Our effective tax rate using book pre-tax income was not meaningful for either period. For both periods, adjustments in the valuation allowance primarily offset changes in net deferred tax assets. See *Financial Statements – Note 9 –Income Taxes* under Part I, Item 1 of this Form 10-Q for additional information.

***Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017***

*Revenues*. Total revenues increased $36.1 million, or 14.6%, to $283.8 million for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. Oil revenues increased $43.3 million, or 25.4%, NGLs revenues increased $2.6 million, or 16.4%, natural gas revenues decreased $10.2 million, or 17.2%, and other revenues increased $0.4 million. The increase in oil revenues was attributable to a 41.9% increase in the average realized sales price to $64.93 per barrel for the six months ended June 30, 2018 from $45.76 per barrel for the six months ended June 30, 2017, partially offset by a decrease in sales volumes of 11.6%. The increase in NGLs revenues was attributable to a 26.5% increase in the average realized sales price to $27.57 per barrel for the six months ended June 30, 2018 from $21.80 per barrel for the six months ended June 30, 2017, partially offset by a decrease in sales volumes of 8.0%. The decrease in natural gas revenues was attributable to a decrease in sales volumes of 3.2 Bcf, or 15.9% and a 1.7% decrease in the average realized price to $2.92 per Mcf for the six months ended June 30, 2018 from $2.97 per Mcf for the six months ended June 30, 2017. Overall, production volumes decreased 13.1% on a Boe basis. The largest production increases for the six months ended June 30, 2018 compared to the three months ended June 30, 2017 were from our newly acquired interest in the Heidelberg field and our Ship Shoal 300 field. Revenue and production was adjusted for royalty relief on two of our deepwater fields related to their 2017 and 2016 production and realized prices which is recognized in the subsequent year. This royalty relief impact to revenues and production during the six months ended June 30, 2018 and 2017 was $1.0 million and $5.0 million, respectively and 286 Boe per day and 967 Boe per day, respectively. Offsetting were production decreases primarily due to natural production declines. Production for the six months ended June 30, 2018 was also negatively impacted by maintenance, well issues and pipeline outages that collectively resulted in deferred production of 4,400 Boe per day. During the six months ended June 30, 2017, deferred production was 2.600 Boe per day.

Revenues from oil and liquids as a percent of our total revenues were 81.9% for the six months ended June 30, 2018 compared to 75.2% for the six months ended June 30, 2017. Our average realized NGLs sales price as a percent of our average realized crude oil sales price decreased to 42.5% for the six months ended June 30, 2018 compared to 47.6% for the six months ended June 30, 2017.

*Lease operating expenses.* Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, increased $0.7 million, or 1.0%, to $72.4 million in the six months ended June 30, 2018 compared to the six months ended June 30, 2017. On a component basis, base lease operating expenses increased $1.4 million, insurance premiums increased $1.3 million, workover expenses decreased $1.8 million, and facilities maintenance expense decreased $0.2 million. Base lease operating expenses increased primarily due the addition of the Heidelberg field; lower product handling and operating charges to an outside party at our Matterhorn field and higher incentive compensation expenses. The insurance premium increase is primarily due to our insurance policies related to named windstorms, which had better coverage between the two periods. The decrease in workover expense was primarily due to a project at our Mahogany field that did not re-occur in 2018. The facility maintenance expense decrease is primarily attributable to compressor overhauls and pipeline projects in 2017, which did not re-occur at the same expense level during 2018.

*Production taxes.* Production taxes were basically flat for the six months ended June 30, 2018 compared to the six months ended June 30, 2017. 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 $1.5 million to $10.0 million for the six months ended June 30, 2018 compared to the six months ended June 30, 2017 primarily due to lower production volumes of all of the commodities we produce.

*Depreciation, depletion, amortization and accretion.* DD&A, which includes accretion for ARO, increased to $11.54 per Boe for the six months ended June 30, 2018 from $10.35 per Boe for the six months ended June 30, 2017. On a nominal basis, DD&A decreased to $77.8 million (3.1%) for the six months ended June 30, 2018 from $80.4 million for the six months ended June 30, 2017. DD&A on a nominal basis decreased primarily due to lower production. Other factors affecting the DD&A rate are capital expenditures, changes in future development costs on remaining reserves and an increase in proved reserves volumes.

*General and administrative expenses*. G&A was $29.3 million for the six months ended June 30, 2018, down 1.6% from $29.7 million for the six months ended June 30, 2017. Decreases in legal costs and share-based compensation as there have been no RSU grants in 2018 and were partially offset by increases in cash-based incentive programs. G&A on a per Boe basis was $4.34 per Boe for the six months ended June 30, 2018 compared to $3.83 per Boe for the six months ended June 30, 2017.

*Derivative (gain) loss.* We entered into derivative contracts for crude oil during the second quarter of 2018 relating to a portion of our 2018 estimated production. The six months ended June 30, 2018 reflects a $6.2 million derivative loss. 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 six months ended June 30, 2017 reflects a $7.6 million derivative gain primarily for our crude oil derivative contracts.

*Interest expense*. Interest expense was $23.5 million and $22.7 million for the six months ended June 30, 2018 and 2017, respectively. The increase is primarily due to an interest accrual related to a royalty issue with the ONRR on production that dates back 10 to 15 years. *See Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information on our debt.

*Gain on exchange of debt.* During the six months ended June 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.

*Other income (expense), net.* During the six months ended June 30, 2017, other expense, net, was $5.1 million and 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 11– Contingencies* under Part I, Item 1 of this Form 10-Q for additional information on the Apache lawsuit.

*Income tax expense (benefit).* Our income tax expense for the six months ended June 30, 2018 was $0.2 million and our income tax benefit for the six months ended June 30, 2017 was $16.6 million. Our current full-year forecast for 2018 has a net operating loss for tax purposes; therefore, no current tax expense was recorded related to the full-year forecast. No deferred income tax expense was recorded for the six months ended June 30, 2018 due to dollar-for-dollar offsets by our valuation allowance. Our effective tax rate using book pre-tax income was not meaningful for either period. For both periods, adjustments in the valuation allowance primarily offset changes in net deferred tax assets. See *Financial Statements – Note 9 –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 changes in regulations or the interpretation of existing regulations.

Our Credit Agreement matures on November 8, 2018. As of June 30, 2018, we had $9.7 million of letters of credit outstanding and no amounts borrowed on our revolving bank credit facility. In April 2018, we consummated a transaction acquiring a 9.375% non-operated working interest in the Heidelberg field, which resulted in the issuance of a letter of credit of $9.4 million and depositing $4.7 million cash with our lead bank under the terms of the Credit Agreement.

Our Unsecured Senior Notes mature on June 15, 2019 and if the Unsecured Senior Notes have not been extended, refunded, defeased, discharged, replaced or refinanced by February 28, 2019, then the 11.00% 1.5 Lien Term Loan, due November 15, 2019, and the 8.50%/10.00% Third Lien PIK Toggle Notes, due June 15, 2021, will both accelerate their maturity to February 28, 2019. If the maturity of these two instruments were to be accelerated, approximately $234.8 million would be payable on February 28, 2019. During 2018, we plan to address the potential maturity acceleration of these two debt instruments and to extend or replace the revolving bank credit facility. We expect to build sufficient cash balances in 2018 to be able to redeem, repurchase or refinance the Unsecured Senior Notes. Certain amendments under the Credit Agreement and the 1.5 Lien Term Loan will likely be required in the event we redeem or repurchase the Unsecured Senior Notes, which we anticipate would be granted if requested. If we are in a position to repay or refinance the 1.5 Lien Term Loan, then we would expect to extend the maturity of our revolving bank credit facility. There can be no assurance that lenders will extend our revolving bank credit facility maturity, but under current market conditions and based on the outlook of our cash position in 2018 and further, we believe our lenders or replacement lenders will be amenable to participating in a refinancing or corporate financing transaction.

*Credit Agreement.* Availability on our revolving bank credit facility as of June 30, 2018 was $140.3 million. 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 2018 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 as of June 30, 2018.

*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. We were in compliance with all applicable covenants of our long-term debt agreements as of June 30, 2018.

*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 financial assurance obligations. During April 2018, we posted an additional $10 million of bonds as requested by BOEM to account for decommissioning obligations that accrued on sole-liability properties during the Company's period of leasing. We and other offshore Gulf of Mexico producers may, in the ordinary course of business, receive requests or 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 materially 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. No additional demands were made to us by sureties during 2018 as of the filing date of the Form 10-Q.

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 six months ended June 30, 2018 was $115.2 million compared to $65.6 million for the six months ended June 30, 2017. The change between periods is primarily due to higher realized prices for crude oil and NGLs, and lower spending for ARO activities. Our combined average realized sales price per Boe increased 31.9% in the six months ended June 30, 2018, which caused total revenues to increase $66.2 million, partially offset by decreases of 13.1% in production volumes which caused revenues to decrease by $30.5 million.

Other items affecting operating cash flows for the six months ended June 30, 2018 were ARO settlements of $12.1 million, which decreased from $36.0 million in the prior period. During the six months ended June 30, 2017, we received insurance reimbursements of $30.1 million and made a deposit related to the Apache matter of $49.5 million. Working capital items accounted for the balance of the change in net cash provided by operating activities.

Net cash used in investing activities during the six months ended June 30, 2018 and 2017 was $77.8 million and $45.5 million, respectively, which represents our investments in oil and gas properties and equipment. Investments in oil and natural gas properties on an accrual basis in the six months ended June 30, 2018 were $31.8 million compared to $43.8 million for the six months ended June 30, 2017. The capital expenditures during the six months ended June 30, 2018 related to investments with the majority in the conventional shelf and to a lesser extent in the deep water. Adjustments from working capital changes associated with investing activities was a net cash decrease of $29.3 million in the six months ended June 30, 2018 compared to net cash decrease of $0.8 million in the six months ended June 30, 2017. These amounts represent timing differences between when the work was performed and the payments are made. In addition, the Heidelberg field net purchase price was $16.6 million during the six months ended June 30, 2018 and there were no similar investments in the prior year period.

Net cash used by financing activities for the six months ended June 30, 2018 and 2017 was $7.1 million and $18.0, respectively. The net cash used for the six months ended June 30, 2018 and 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.

*Derivative Financial Instruments.* From time to time, we use various derivative instruments tomanage 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. During the six months ended June 30, 2018, we entered into derivative contracts for crude oil which relate to volumes of 11,000 barrels per day through December 2018. See *Financial Statements – Note 7 – 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 $162.5 million aggregate limit covering all of our higher valued properties, and $150 million for all other properties subject to a retention (deductible) of $30.0 million. Included within the $162.5 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 for one year beginning 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 for one year beginning 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, 2018, and our Energy Package effective on June 1, 2018, 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. 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 crude oil, NGLs and natural gas, acquisition opportunities, available liquidity and the results of our exploration and development activities. During the six months ended June 30, 2018, we received reimbursement of capital expenditures from Monza for projects in the JV Drilling Program which had incurred costs during 2017. These reimbursements related to 2017 are reported in a separate line in the table below. The following table presents our capital expenditures on an accrual basis for exploration, development and other leasehold costs:

| | Six Months Ended June 30, | |
|---|---|---|
| | 2018 | 2017 |
| | (In thousands) | |
| Exploration (1) | $ 4,322 | $ (401) |
| Development (1) | 33,003 | 42,440 |
| Heidelberg field | 16,617 | — |
| Reimbursement from Monza for 2017 expenditures | (14,075) | — |
| Seismic, JV Drilling Program and other | 8,553 | 1,761 |
| Investments in oil and gas property/equipment | $ 48,420 | $ 43,800 |

(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:

| | Six Months Ended June 30, | |
|---|---|---|
| | 2018 | 2017 |
| | (In thousands) | |
| Conventional shelf | $ 28,128 | $ 41,032 |
| Deepwater | 9,197 | 1,007 |
| Exploration and development capital expenditures | $ 37,325 | $ 42,039 |

Our capital expenditures for the six months ended June 30, 2018 were financed by cash flow from operations and cash on hand.

During the six months ended June 30, 2018, we completed the A-17 well at Mahogany, which began producing during March 2018 and we completed the Viosca Knoll 823 (“Virgo”) A-10 ST well, which began production during April 2018. The Virgo A-10 ST well is in the JV Drilling Program. During the six months ended June 30, 2017, we completed three wells. We did not drill any dry holes in either period.

*Exploration/Development Activities.* As of July 31, 2018, we were drilling on the Virgo A-12 well and the South Timbalier 311 A-2 well. During July 2018, we completed the Mahogany A-5 well and it began producing in July 2018. The Main Pass 286 #1 well has been cased and is waiting for development sanction. Each of these four wells is in the JV Drilling Program. In addition, we have moved the rig at Mahogany to drill the A-19 well, which is not in the JV Drilling Program.

*Offshore Lease Awards.* We were successful in obtaining nine new leases in the Central and Eastern Gulf of Mexico. The new leases are primarily located near or offsetting our existing properties and were acquired in total for less than $1.0 million, net to our interest.

*Divestitures.* Periodically, we sell properties as part of the management of our property portfolio. During the six months ended June 30, 2018, we did not have any property sales of significance.

*Capital Expenditure Budget and Expected Production for 2018.* Our current 2018 capital expenditure forecast is approximately $95 million, which excludes the Heidelberg field transaction and excludes other potential acquisitions. The forecast also incorporates the JV Drilling Program. Our 2018 capital expenditure program includes participation in 10 wells, seven of which are included in the 2018 JV Drilling Program. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments.

*Income Taxes.* As of June 30, 2018, we have current income tax receivables of $65.2 million. The current income tax receivables include an estimated net operating loss claim for 2017 of $13.1 million, which is expected to be received during 2018. The other component of current income tax receivables relates to our net operating loss claims totaling $52.1 million for the years 2012, 2013 and 2014 that were carried back to prior years and are expected to be received in 2018. These receivables relate to claims under rules for “specified liability losses” made pursuant to IRC Section 172(f), which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. For 2018, we do not expect to make any significant income tax payments. See *Financial Statements – Note 9 – 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 June 30, 2018 and December 31, 2017 were $317.2 million and $300.4 million, respectively. Our plans include spending $37.6 million in 2018 for ARO compared to $72.4 million spent on ARO in 2017. As our ARO estimates are for work to be performed in the future, and in the case of our non-current ARO, extend from one to 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, 2017 for additional information.

*Contractual Obligations.* Updated information on certain contractual obligations is provided in *Financial Statements – Note 2 – Long-Term Debt* and *Note 6 – Asset Retirement Obligations,* and under Part I, Item 1 of this Form 10-Q. As of June 30, 2018, drilling rig commitments, excluding ARO drilling rig commitments, were approximately $5.4 million compared to $5.7 million as of December 31, 2017. In conjunction with the purchase of the Heidelberg field interest, we assumed contracts with certain pipeline companies that contain minimum quantities obligations through 2028 resulting in an estimated commitment of $19.6 million. Except for scheduled utilization, other contractual obligations as of June 30, 2018 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, 2017.

**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, 2017. 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 three months ended June 30, 2018 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, 2017. 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, 2017.

*Commodity Price Risk.* Our revenues, profitability and future rate of growth substantially depend upon market prices of crude oil, NGLs and natural gas, which fluctuate widely. Crude oil, NGLs and natural gas price declines have adversely affected our revenues, net cash provided by operating activities and profitability in the past and could have impacts on our business in the future. During the second quarter of 2018, we entered into derivative crude oil contracts related to a portion of our estimated production for the remainder of 2018. 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 crude oil and natural gas prices, but they also may limit future income from favorable price movements. See *Financial Statements – Note 7 – Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q for additional information.

*Interest Rate Risk.* As of June 30, 2018, 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 June 30, 2018, 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 June 30, 2018, 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 June 30, 2018, 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 *Financial Statements – Note 11 – Contingencies*, under Part I Item 1 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, 2017, 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 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, 2017 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, 2017.

**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 August 2, 2018.

**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: August 2, 2018

/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: August 2, 2018

/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 June 30, 2018 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, 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: August 2, 2018

/s/ Tracy W. Krohn

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

Date: August 2, 2018

/s/ John D. Gibbons

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