W&T OFFSHORE INC
Form 10-Q
August 05, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016

or

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______________ to ________________

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

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

(713) 626-8525

(Registrant's telephone number, including area code)

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

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

Large accelerated filer ¨	Accelerated filer þ
Non-accelerated filer ¨	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company.   Yes ¨   No þ

As of August 2, 2016, there were 76,634,957 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	June 30, 2016 (Unaudited)	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$171,824	$85,414
Receivables:		
Oil and natural gas sales	34,841	35,005
Joint interest and other	20,145	22,012
Income taxes	5,599	—
Total receivables	60,585	57,017
Prepaid expenses and other assets	18,258	26,879
Total current assets	250,667	169,310
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which $5,267 at June 30, 2016 and $18,595 at December 31, 2015 were excluded from amortization)	7,901,252	7,902,494
Furniture, fixtures and other	20,873	20,802
Total property and equipment	7,922,125	7,923,296
Less accumulated depreciation, depletion and amortization	7,266,289	6,933,247
Net property and equipment	655,836	990,049
Deferred income taxes	8,463	27,595
Restricted deposits for asset retirement obligations	26,409	15,606
Income tax receivables	52,097	—
Other assets	4,882	5,462
Total assets	$998,354	$1,208,022
Liabilities and Shareholders' Deficit		
Current liabilities:		
Accounts payable	$92,852	$109,797
Undistributed oil and natural gas proceeds	20,659	21,439
Asset retirement obligations	91,296	84,335
Accrued liabilities	12,011	11,922
Total current liabilities	216,818	227,493
Long-term debt	1,345,051	1,196,855
Asset retirement obligations, less current portion	252,826	293,987
Other liabilities	16,462	16,178

Commitments and contingencies	—	—
Shareholders' deficit:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at June 30, 2016 and December 31, 2015	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 79,504,130 issued and 76,634,957 outstanding at June 30, 2016; 79,375,662 issued and 76,506,489 outstanding at December 31, 2015	1	1
Additional paid-in capital	428,618	423,499
Retained earnings (deficit)	(1,237,255)	(925,824)
Treasury stock, at cost; 2,869,173 shares at June 30, 2016 and December 31, 2015	(24,167)	(24,167)
Total shareholders' deficit	(832,803)	(526,491)
Total liabilities and shareholders' deficit	$998,354	$1,208,022

See Notes to Condensed Consolidated Financial Statements

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands except per share data) (Unaudited)			
Revenues	$99,655	$149,066	$177,370	$276,973
Operating costs and expenses:				
Lease operating expenses	36,622	45,130	81,091	98,461
Production taxes	370	1,000	896	1,637
Gathering and transportation	6,398	4,793	11,490	9,617
Depreciation, depletion, amortization and accretion	57,493	103,342	121,226	228,809
Ceiling test write-down of oil and natural gas properties	104,592	252,772	221,151	513,162
General and administrative expenses	16,235	19,757	32,678	40,523
Derivative loss	4,942	1,078	2,449	1,078
Total costs and expenses	226,652	427,872	470,981	893,287
Operating loss	(126,997)	(278,806)	(293,611)	(616,314)
Interest expense:				
Incurred	29,773	26,116	57,587	49,062
Capitalized	(102)	(2,024)	(445)	(3,807)
Other (income) expense, net	(24)	1,685	1,282	1,683
Loss before income tax benefit	(156,644)	(304,583)	(352,035)	(663,252)
Income tax benefit	(35,722)	(44,134)	(40,604)	(147,708)
Net loss	$(120,922)	$(260,449)	$(311,431)	$(515,544)
Basic and diluted loss per common share	$(1.58)	$(3.43)	$(4.07)	$(6.79)

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' DEFICIT

	Common Stock Outstanding Shares	Common Stock Value	Additional Paid-In Capital	Retained Earnings (Deficit)	Treasury Stock Shares	Treasury Stock Value	Total Shareholders' Deficit
	(In thousands) (Unaudited)						
Balances at December 31, 2015	76,506	$ 1	$ 423,499	$ (925,824)	2,869	$ (24,167)	$ (526,491)
Share-based compensation	—	—	5,121	—	—	—	5,121
Stock Issued	129	—	—	—	—	—	—
Other	—	—	(2)	—	—	—	(2)
Net loss	—	—	—	(311,431)	—	—	(311,431)
Balances at June 30, 2016	76,635	$ 1	$ 428,618	$ (1,237,255)	2,869	$ (24,167)	$ (832,803)

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2016	2015
	(In thousands) (Unaudited)	
Operating activities:		
Net loss	$(311,431)	$(515,544)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion, amortization and accretion	121,226	228,809
Ceiling test write-down of oil and natural gas properties	221,151	513,162
Debt issuance costs write-off/amortization of debt items	1,880	2,432
Share-based compensation	5,121	5,708
Derivative loss	2,449	1,078
Cash receipts on derivative settlements	4,746	—
Deferred income taxes	19,285	(147,708)
Changes in operating assets and liabilities:		
Oil and natural gas receivables	1,226	15,285
Joint interest and other receivables	1,763	11,036
Income taxes	(57,931)	(325)
Prepaid expenses and other assets	(10,365)	8,929
Asset retirement obligation settlements	(25,156)	(21,939)
Accounts payable, accrued liabilities and other	14,767	(20,013)
Net cash provided by (used in) operating activities	(11,269)	80,910
Investing activities:		
Investment in oil and natural gas properties and equipment	(17,712)	(150,994)
Changes in operating assets and liabilities associated with investing activities	(34,122)	(50,849)
Proceeds from sales of assets	1,500	—
Purchases of furniture, fixtures and other	(70)	(709)
Net cash used in investing activities	(50,404)	(202,552)
Financing activities:		
Borrowings of long-term debt - revolving bank credit facility	340,000	194,000
Repayments of long-term debt - revolving bank credit facility	(192,000)	(381,000)
Issuance of 9.00% Term Loan	—	297,000
Debt issuance costs	—	(6,407)
Other	83	54
Net cash provided by financing activities	148,083	103,647
Increase (decrease) in cash and cash equivalents	86,410	(17,995)
Cash and cash equivalents, beginning of period	85,414	23,666
Cash and cash equivalents, end of period	$171,824	$5,671

See Notes to Condensed Consolidated Financial Statements.

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

1. Basis of Presentation

Operations. W&T Offshore, Inc. (with subsidiaries referred to herein as "W&T," "we," "us," "our," or the "Company") is an independent oil and natural gas producer with operations offshore in the Gulf of Mexico. The Company is active in the exploration, development and acquisition of oil and natural gas properties. Our interest 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"). On October 15, 2015, a substantial amount of our interest in onshore acreage was sold, which is described in Note 2.

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, 2015.

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 prices of these commodities began falling in the second half of 2014, continued to generally decline in 2015, and declined further in the first half of 2016 on an average basis. Steps taken during 2015 and the first half of 2016 to mitigate the effects of these lower prices include: (i) significantly reducing the budgeted capital spending for 2015 and 2016 from historical levels; (ii) continuing the suspension of our drilling and completion activities at several locations; (iii) continued suspension of the regular quarterly common stock dividend; (iv) selling our interests in the Yellow Rose field in the fourth quarter of 2015; (v) reducing our headcount of employees and contractors; and (vi) continuing the implementation of numerous projects to reduce our operating costs. See our Annual Report on Form 10-K for the year ended December 31, 2015 concerning risks related to our business and events occurring during 2015 and other information and the Notes herein for additional information.

In February and March 2016, we received several orders from the Bureau of Ocean Energy Management ("BOEM") requiring that we provide additional security in the aggregate of $260.8 million, with amounts specified with respect to certain designated leases, rights of use and easement ("RUE") and rights of way ("ROW"). We have filed appeals with the Interior Board of Land Appeals ("IBLA"), and the IBLA, acknowledging the on-going settlement discussions with the BOEM, stayed the effectiveness of the BOEM orders to August 31, 2016.

We have assessed our financial condition, the current capital markets and options given different scenarios of commodity prices and believe we will have adequate liquidity to fund our operations through June 30, 2017; however, we cannot predict how an extended period of low commodity prices or the impact of future bonding requirements will affect our operations, liquidity levels and compliance with debt covenants.

On July 25, 2016, we announced commencement of an exchange offer and consent solicitation to eligible holders for certain notes and, in conjunction with the exchange offer, obtaining $75.0 million of additional capital through borrowings on a term loan (the "1.5 Lien Term Loan"), which will be junior only to the revolving bank credit facility and certain other customary permitted liens and will be secured by a 1.5 priority lien on all assets granted to secure indebtedness under our revolving bank credit facility. The net proceeds from the 1.5 Lien Term Loan will be used to reduce borrowings under our revolving bank credit facility. The exchange offer, consents and 1.5 Lien Term Loan will be subject to additional approvals and agreements with certain stakeholders. Such transactions, if successful, will enhance our liquidity and help our ability to continue as a going-concern entity.

See Notes 11 and 12 for additional information.

Ceiling Test Write-Down. Under the full cost method of accounting, each quarter we are required to perform a "ceiling test," which determines a limit on the book value of our oil and natural gas properties. If the net capitalized cost of oil and natural gas properties (including capitalized asset retirement obligations ("ARO")) net of related deferred income taxes exceeds the ceiling test limit, the excess is charged to expense on a pre-tax basis and separately disclosed. Any such write downs are not recoverable or reversible in future periods. The ceiling test limit is calculated as: (i) the present value of estimated future net revenues from proved reserves, less estimated future development costs, discounted at 10%; (ii) plus the cost of unproved oil and natural gas properties not being amortized; (iii) plus the lower of cost or estimated fair value of unproved oil and natural gas properties included in the amortization base; and (iv) less related income tax effects. Estimated future net revenues used in the ceiling test for each period are based on current prices for each product, defined by the SEC as the unweighted average of first-day-of-the-month commodity prices over the prior twelve months for that period. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials.

Due primarily to declines in the unweighted rolling 12-month average of first-day-of-the-month commodity prices for oil and natural gas, we recorded ceiling test write-downs in the first two quarters of 2016 and in every quarter of 2015, which are reported as a separate line in the Statements of Operations. The average price using the SEC required methodology at June 30, 2016 was $39.63 per barrel for West Texas Intermediate ("WTI") crude oil and $2.24 per million British Thermal Unit ("MMBtu") for Henry Hub natural gas before adjustments. Ceiling test write-downs of the carrying value of our oil and natural gas properties for the six months ended June 30, 2016 and 2015 were $221.2 million and $513.2 million, respectively. The ceiling test write-down for the full year of 2015 was $987.2 million. If crude oil and natural gas prices decrease from current levels, it is probable that a ceiling test write-down will be recorded in the third quarter of 2016.

Prepaid Expenses and Other. Amounts recorded in Prepaid expenses and other on the Condensed Consolidated Balance Sheets are expected to be realized within one year. Major categories are disclosed in the following table (in thousands):

	June 30,	December 31,

	2016	2015
Derivative assets – current[1]	$671	$ 10,036
Prepaid insurance and surety bonds	9,172	7,475
Prepaid deposits related to royalties	5,373	5,943
Other	3,042	3,425
Prepaid expenses and other	$18,258	$ 26,879

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

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Recent Accounting Developments. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09 ("ASU 2014-09"), Summary and Amendments That Create Revenue from Contracts and Customers (Subtopic 606). ASU 2014-09 amends and replaces current revenue recognition requirements, including most industry-specific guidance. The revised guidance establishes a five step approach to be utilized in determining when, and if, revenue should be recognized. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. Upon application, an entity may elect one of two methods, either restatement of prior periods presented or recording a cumulative adjustment in the initial period of application. We have not determined the effect ASU 2014-09 will have on the recognition of our revenue, if any, nor have we determined the method we will utilize upon adoption, which would be in the first quarter of 2018.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15 ("ASU 2014-15"), Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern (Subtopic 205-40). The guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual and interim periods thereafter. We do not expect the revised guidance to materially affect our evaluation as to being a going concern, or have an effect on our financial statements or related disclosures.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02 ("ASU 2016-02"), Leases (Subtopic 842). Under the new guidance, a lessee will be required to recognize assets and liabilities for leases with lease terms of more than 12 months. Consistent with current GAAP, the recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. However, unlike current GAAP, which requires only capital leases to be recognized on the balance sheet, ASU 2016-02 will require both types of leases to be recognized on the balance sheet. ASU 2016-02 also will require disclosures to help investors and other financial statement users to better understand the amount, timing and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative requirements, providing additional information about the amounts recorded in the financial statements. ASU 2016-02 does not apply to leases for oil and gas properties, but does apply to equipment used to explore and develop oil and gas resources. Our current operating leases that will be impacted by ASU 2016-02 when it is effective are leases for office space in Houston and New Orleans, although ASU 2016-02 may impact the accounting for leases related to operations equipment depending on the term of the lease. We currently do not have any leases classified as financing leases. ASU 2016-02 is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using the modified retrospective approach. We have not yet fully determined or quantified the effect ASU 2016-02 will have on our financial statements.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09 ("ASU 2016-09"), Compensation – Stock Compensation (Subtopic 718). The objective of ASU 2016-09 is for simplification involving several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. ASU 2016-09 is effective for annual and interim periods beginning after December 15, 2016 and early adoption is permitted. We have not yet fully determined or quantified the effect ASU 2016-09 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.

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

2. Divestitures

2015 Divestiture

On October 15, 2015, we sold certain onshore oil and natural gas property interests to Ajax Resources, LLC ("Ajax") for approximately $370.9 million in cash, which includes certain customary post effective date price adjustments, and Ajax assumed responsibility for the related ARO and other associated liabilities. The effective date of the sale was January 1, 2015. A net purchase price adjustment of $0.9 million for final customary effective date adjustments was recorded during the six months ended June 30, 2016. Ajax acquired all of our interest in the Yellow Rose field in the Permian Basin, covering approximately 25,800 net acres in Andrews, Martin, Gaines and Dawson counties in West Texas. We retained a non-expense bearing overriding royalty interest ("ORRI") equal to a variable percentage in production from the working interests assigned to Ajax, which percentage varies on a sliding scale from one percent for each month that the New York Mercantile Exchange ("NYMEX") prompt month contract trading price for light sweet crude oil is at or below $70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than $90.00 per barrel.

Under the full cost method, sales or abandonments of oil and natural gas properties, whether or not being amortized, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to the cost center. The sale to Ajax did not represent greater than 25% of the Company's proved reserves of oil and natural gas attributable to the full cost pool. As a result, alteration in the relationship between capitalized costs and proved reserves of oil and natural gas attributable to the full cost pool was not deemed significant and no gain or loss was recognized from the sale.

3. 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 in accordance with applicable laws.

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

Balance, December 31, 2015	$378,322
Liabilities settled	(25,156)
Accretion of discount	9,335
Revisions of estimated liabilities (1)	(18,379)
Balance, June 30, 2016	344,122
Less current portion	91,296
Long-term	$252,826

(1) Revisions were primarily related to reduced cost estimates from service providers for plug and abandonment work at certain locations.

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4. Derivative Financial Instruments

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

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

For information about fair value measurements, refer to Note 6.

Commodity Derivatives

As of June 30, 2016, we have open crude oil and natural gas derivative contracts for a portion of our anticipated future production for the remainder of 2016. These contracts were entered into during the second quarter of 2015. The open oil derivative contracts are known as "two-way collars" consisting of a purchased put option and a sold call option. These two-way collars provide price risk protection if crude oil prices fall below certain levels, but may limit incremental income from favorable price movements above certain limits. The oil contracts are based on WTI crude oil prices as quoted off the NYMEX. The open natural gas derivative contracts are known as "three-way collars" consisting of a purchased put option, a sold call option and a purchased call option, each at varying strike prices. The three-way collar contracts are structured to provide price risk protection if the commodity price falls below the strike price of the put option and provides us the opportunity to benefit if the commodity price rises above the strike price of the purchased call option. These contracts may have the effect of reducing some of our incremental income from favorable price movements if the commodity price is above certain levels, but have unlimited upside potential if prices rise above those levels. The natural gas contracts are based on Henry Hub natural gas prices as quoted off the NYMEX. The strike prices of both the oil and natural gas contracts were set so that the contracts were premium neutral ("costless"), which means no net premium was paid to or received from a counterparty.

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

As of June 30, 2016, our open commodity derivative contracts were as follows:

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

		Notional (1) Quantity (Bbls/day)	Notional (1) Quantity (Bbls)	Weighted Average Contract Price Put Option (Bought)	Weighted Average Contract Price Call Option (Sold)
Termination Period					
2016:	3rd Quarter	5,000	460,000	$40.00	$81.47
	4th Quarter	5,000	460,000	40.00	81.47

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

		Notional (1) Quantity (MMBTUs/day)	Notional (1) Quantity (MMBTUs)	Weighted Average Contract Price Put Option (Bought)	Weighted Average Contract Price Call Option (Sold)	Weighted Average Contract Price Call Option (Bought)
Termination Period						
2016:	3rd Quarter (2)	40,000	2,440,000	$2.25	$3.50	$ 3.77
	4th Quarter	40,000	3,680,000	2.25	3.50	3.77

(1) Volume Measurements: Bbls – barrelsMMBTUs – million British Thermal Units.
(2) The natural gas derivative contracts are priced and closed in the last week prior to the related production month. Natural gas derivative contracts related to July 2016 production were priced and closed in June 2016 and are not included in the above table as these were not open derivative contracts as of June 30, 2016.

The following balance sheet line items included amounts related to the estimated fair value of our open commodity derivative contracts as indicated in the following table (in thousands):

	June 30, 2016	December 31, 2015
Prepaid and other assets	$594	$ 7,672
Accrued liabilities	117	—

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

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Derivative loss	$4,942	$1,078	$2,449	$1,078

Cash receipts, net, on commodity derivative contract settlements 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,	
	2016	2015
Cash receipts on derivative settlements, net	$4,746	$ —

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Offsetting Commodity Derivatives

During 2016 and 2015, all our commodity derivative contracts permit netting of derivative gains and losses upon settlement. In general, the terms of the contracts provide for offsetting of amounts payable or receivable between us and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same commodity. If an event of default were to occur causing an acceleration of payment under our revolving bank credit facility, that event may also trigger an acceleration of settlement of our derivative instruments. If we were required to settle all of our open derivative contracts, we would be able to net payments and receipts per counterparty pursuant to the derivative contracts. Although our derivative contracts allow for netting, which would allow for recording assets and liabilities per counterparty on a net basis, we have historically accounted for our derivative contracts on a gross basis per contract as either an asset or liability.

5. Long-Term Debt

Our long-term debt was as follows (in thousands):

	June 30, 2016	December 31, 2015
8.50% Senior Notes:		
Principal	$900,000	$900,000
Debt premiums, net of amortization	9,151	10,503
Debt issuance costs, net of amortization	(5,417)	(6,274)
9.00% Term Loan:		
Principal	300,000	300,000
Debt discounts, net of amortization	(2,437)	(2,689)
Debt issuance costs, net of amortization	(4,246)	(4,685)
Revolving bank credit facility	148,000	—
Total long-term debt	1,345,051	1,196,855
Current maturities of long-term debt	—	—
Long term debt, less current maturities	$1,345,051	$1,196,855

8.50% Senior Notes

At June 30, 2016 and December 31, 2015, our outstanding senior notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019 (the “8.50% Senior Notes”), were classified as long-term at their carrying value. Interest on the 8.50% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the 8.50% Senior Notes is 8.4%, which includes amortization of debt issuance costs and premiums. We are subject to various financial and other covenants under the indenture governing the 8.50% Senior Notes, and we were in compliance with those covenants as of June 30, 2016.

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

9.00% Term Loan

At June 30, 2016 and December 31, 2015, our outstanding term loan, which bears an annual interest rate of 9.00% and matures on May 15, 2020 (the “9.00% Term Loan”), was classified as long-term at its carrying value. Interest on the 9.00% Term Loan is payable in arrears semi-annually on May 15 and November 15. The estimated annual effective interest rate on the 9.00% Term Loan is 9.7%, which includes amortization of debt issuance costs and discounts. The 9.00% Term Loan is secured by a second priority lien covering our oil and gas properties to the extent such properties secure first priority liens granted to secure indebtedness under our Credit Agreement. We are subject to various covenants under the terms governing the 9.00% Term Loan including, without limitation, covenants that limit our ability to incur other debt, pay dividends or distributions on our equity, merge or consolidate with other entities and make certain investments in other entities. We were in compliance with those covenants as of June 30, 2016.

Credit Agreement

The Credit Agreement provides a revolving bank credit facility. Availability under the Credit Agreement is subject to a semi-annual borrowing base determination set at the discretion of our lenders, and the Company and the lenders may each request one additional determination per year. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base, such excess is required to be repaid within 90 days in three equal monthly payments. Letters of credit may be issued in amounts up to $150.0 million, provided availability under the revolving bank credit facility exists. The revolving bank credit facility is secured and is collateralized by our oil and natural gas properties. The Credit Agreement terminates on November 8, 2018.

The Credit Agreement contains various customary covenants for certain financial tests, as defined in the Credit Agreement and measured as of the end of each quarter, and for customary events of default. These financial test ratios and limits as of March 31, 2016 and thereafter are: (i) the First Lien Leverage Ratio must be less than 1.50 to 1.00; (ii) the Current Ratio must be greater than 1.00 to 1.00; and (iii) the Secured Debt Leverage Ratio must be less than 3.50 to 1.00. As of June 30, 2016, our the First Lien Ratio was 0.95 to 1.00, the Current Ratio was 2.01 to 1.00 and the Secured Debt Leverage Ratio was 2.86 to 1.00. 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 8.50% Senior Notes and the 9.00% Term Loan, and these agreements contain similar cross-default clauses with the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of June 30, 2016.

On March 23, 2016, the banks reduced our borrowing base from $350.0 million to $150.0 million in connection with the spring borrowing base redetermination. Pursuant to the terms of the Credit Agreement, we repaid the borrowing base deficiencies to be in conformity with the limitation of the new borrowing base as of June 30, 2016. The reduction in the borrowing base resulted in a proportional reduction in the unamortized costs related to the Credit Agreement of $1.4 million for the six months ended June 30, 2016, which is included in the line Other expense, net on the Condensed Statement of Operations.

The estimated annual effective interest rate was 5.5% for the six months ended June 30, 2016 for average daily borrowings outstanding under the revolving bank credit facility. The estimated annual effective interest rate includes amortization of debt issuance costs and excludes commitment fees and other costs. As of both June 30, 2016 and

December 31, 2015, we had $0.9 million of letters of credit outstanding under the revolving bank credit facility

For information about fair value measurements for our 8.50% Senior Notes, 9.00% Term Loan and revolving bank credit facility, refer to Note 6.

See Note 12 for information on events occurring subsequent to June 30, 2016 concerning the 8.50% Senior Notes.

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6. Fair Value Measurements

We measure the fair value of our open derivative financial instruments by applying the income approach, using models with inputs that are classified within Level 2 of the valuation hierarchy. The inputs used for the fair value measurement of our derivative financial instruments are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads, credit risk and published commodity futures prices. The fair values of our 8.50% Senior Notes and 9.00% Term Loan were based on quoted prices, although the market is not an active market; therefore, the fair value is classified within Level 2. The carrying amount of debt under our revolving bank credit facility approximates fair value because the interest rates are variable and reflective of market rates.

The following table presents the fair value of our open derivatives and long-term debt, as reported in the Condensed Consolidated Balance Sheets (in thousands):

		June 30, 2016		December 31, 2015	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$594	$117	$7,672	$—
8.50% Senior Notes [(1)]	Level 2	—	222,750	—	324,000
9.00% Term Loan [(1)]	Level 2	—	183,000	—	217,500
Revolving bank credit facility [(1)]	Level 2	—	148,000	—	—

(1) The long-term debt items are reported on the Condensed Consolidated Balance Sheets at their carrying value as described in Note 5.

7. 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 and in May 2016. The May 2016 amendment increased the number of shares available in the Plan by 3,300,000 shares. As allowed by the Plan, during 2015 and 2014, the Company granted restricted stock units ("RSUs") to certain of its employees. During the six months ended June 30, 2016, no RSUs were granted. RSUs are a long-term compensation component of the Plan, which are granted to only 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, 2016, there were 7,537,208 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. Although the Company has the option at vesting to settle RSUs in stock or cash, or a combination of stock and cash, only common stock has been used to settle vested RSUs to date.

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

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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 2015 and 2014 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. Dividend equivalents are earned at the same rate as dividends are paid on our common stock, if any, after achieving the specified performance requirements for the RSUs.

A summary of activity in 2016 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, December 31, 2015	3,474,079	$ 7.42
Vested	(3,400)	18.45
Forfeited	(86,838)	7.01
Nonvested, June 30, 2016	3,383,841	7.42

For the outstanding RSUs issued to the eligible employees as of June 30, 2016, vesting is expected to occur as follows:

	Restricted Stock Units
2016	977,423
2017	2,406,418
Total	3,383,841

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 2016, 2015 and 2014. As of June 30, 2016, there were 317,896 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. 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.

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A summary of activity in 2016 related to Restricted Shares is as follows:

	Restricted Shares	
	Shares	Weighted Average Grant Date Fair Value Per Share
Nonvested, December 31, 2015	78,230	$ 8.95
Granted	126,128	2.22
Vested	(43,062)	9.75
Nonvested, June 30, 2016	161,296	3.47

Restricted Shares fair value at grant date and vested date: The fair value of Restricted Shares granted during the six months ended June 30, 2016 was $0.3 million based on the Company's closing price on the date of grant. The fair value of Restricted Shares that vested during the six months ended June 30, 2016 was $0.1 million based on the Company's closing price on the date of vesting.

For the outstanding Restricted Shares issued to the non-employee directors as of June 30, 2016, vesting is expected to occur as follows:

	Restricted Shares
2017	62,136
2018	57,120
2019	42,040
Total	161,296

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Share-based compensation expense from:				
Restricted stock units	$2,439	$2,802	$4,888	$5,619
Restricted Shares	146	90	233	183
Common shares	—	—	—	(94)
Total	$2,585	$2,892	$5,121	$5,708
Share-based compensation tax benefit:				

Tax benefit computed at the statutory rate	$904	$1,012	$1,792	$1,998

Unrecognized Share-Based Compensation. As of June 30, 2016, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $7.9 million and $0.5 million, respectively. Unrecognized share-based compensation expense will be recognized through November 2017 for RSUs and April 2019 for Restricted Shares.

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

During 2015, the Company issued cash-based incentive awards for 2015 that, in addition to being performance-based awards related to 2015 criteria, the payment of such awards is contingent on the Company achieving the following financial condition on or before December 31, 2017: Adjusted EBITDA less Interest Expense, as reported by the Company in its announced Earnings Release with respect to the end of any fiscal quarter plus three preceding quarters, exceeds $300.0 million. As the Company did not achieve this financial condition up through June 30, 2016, no amounts have been recognized to date related to the 2015 cash-based incentive awards. During the six months ended June 30, 2016, no cash-based awards have been issued.

8. Income Taxes

Our income tax benefit for the three and six months ended June 30, 2016 was $35.7 million and $40.6 million, respectively. The annualized effective tax rate for the three and six months ended June 30, 2016 was 22.8% and 11.5%, respectively. Our income tax benefit for the three and six months ended June 30, 2015 was $44.1 million and $147.7 million, respectively. The annualized effective tax rate for the three and six months ended June 30, 2015 was 14.5% and 22.3%, respectively. Our annualized effective tax rates differ from the federal statutory rate of 35.0% for all periods presented primarily due to recording and adjusting a valuation allowance for our deferred tax assets.

During the three months and six ended June 30, 2016, we recorded a valuation allowance of $22.3 million and $82.2 million, respectively, related to federal and state deferred tax assets. During the three and six months ended June 30, 2015, we recorded a valuation allowance of $62.9 million and $85.4 million, respectively. Deferred tax assets are recorded related to net operating losses 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 addition, the realization depends on the ability to carryback certain items to prior years for refunds of taxes previously paid. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. As of June 30, 2016 and December 31, 2015, we had a valuation allowance related to Federal, Louisiana and Alabama net operating losses and other deferred taxes. The tax years 2012 through 2015 remain open to examination by the tax jurisdictions to which we are subject.

As of June 30, 2016, we recorded a current income tax receivable of $5.6 million and non-current income tax receivables of $52.1 million. For the current income tax receivable, the amount is comprised principally of a net operating loss (“NOL”) claim for 2015 carried back to 2005 filed on Form 1139, Corporation Application for Tentative Refund. For the net amount classified as non-current income tax receivables, our NOL claims for the years 2012, 2013 and 2014 were carried back to the years 2003, 2004, 2007, 2010 and 2011 filed on Form 1120X, U.S. Corporation Income Tax Return. These carryback claims are made pursuant to Internal Revenue Code (“IRC”) Section 172(f) which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. The refund claims filed on Form 1120X will require a review by the Congressional Joint Committee on Taxation and are accordingly classified as non-current.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the 2016 and 2015 periods reported, we recorded immaterial amounts of accrued interest expense related to our unrecognized tax benefit.

9. Loss Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net loss	$(120,922)	$(260,449)	$(311,431)	$(515,544)
Weighted average common shares outstanding	76,457	75,910	76,443	75,884
Basic and diluted loss per common share	$(1.58)	$(3.43)	$(4.07)	$(6.79)
Shares excluded due to being anti-dilutive (weighted-average)	3,531	1,931	3,529	1,962

10. Dividends

During the six months ended June 30, 2016 and the full year of 2015, we did not pay any dividends and a suspension of dividends remains in effect.

11. Contingencies

Supplemental Bonding Requirements by the BOEM. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or post surety bonds or other acceptable financial assurances that such decommissioning obligations will be satisfied. Prior to 2015, we were partially exempt from providing such financial assurances. The significant and sustained decline in crude oil and natural gas prices, however, has resulted in the Company no longer meeting the relevant financial strength and reliability criteria for such exemptions set forth in the current regulations and procedures of the BOEM. As a result, we were notified by the BOEM in 2015 that the Company was no longer eligible for any exemption from providing financial assurances to the BOEM. In February and March 2016, we received several demands from the BOEM ordering that we provide additional security in the aggregate of $260.8 million, with amounts specified with respect to certain designated leases, rights of use and easement and rights of way. We have filed appeals with the IBLA regarding four of the BOEM orders - specifically the February order requiring the Company to post a total of $159.8 million in additional security and three March orders requiring $101.0 million in additional security. The IBLA, acknowledging that the BOEM and the Company were seeking to resolve the BOEM orders through settlement discussions, stayed the effectiveness of the orders until June 30, 2016. Because settlement discussions were ongoing, on June 30, 2016, the IBLA again stayed the effectiveness of the orders until August 31, 2016. We continue to have discussions with the BOEM and its sister agency, the Bureau of Safety and Environmental Enforcement (the “BSEE”), in an effort to seek an acceptable resolution of the orders.

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

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Notification by ONRR of Fine for Non-compliance. In December 2013 and January 2014, we were notified by the Office of Natural Resources Revenue ("ONRR") of an underpayment of royalties on certain Federal offshore oil and gas leases that cumulatively approximated $30,000 over several years, which represents 0.0045% of royalty payments paid by us during the same period of the underpayment. In March 2014, we received notice from the ONRR of a statutory fine of $2.3 million (subsequently reduced to approximately $1.1 million) relative to such underpayment. We believe the fine is excessive considering the circumstances and in relation to the amount of underpayment. On April 23, 2014, we filed a request for a hearing on the record and a general denial of the ONRR's allegations contained in the notice. We intend to contest the fine to the fullest extent possible. A hearing on this matter is scheduled with an Administrative Law Judge on August 30, 2016 in Houston, Texas. The ultimate resolution may result in a waiver of the fine, a reduction of the fine, or payment of the full amount plus interest covering several years. As no amount has been determined as more likely than any other within the range of possible resolutions, no amount has been accrued as of June 30, 2016 or December 31, 2015.

Apache Lawsuit. On December 15, 2014, Apache Corporation ("Apache") filed a lawsuit against W&T Offshore, Inc., alleging that W&T breached the joint operating agreement ("JOA") related to deepwater wells in the Mississippi Canyon area of the Gulf of Mexico. That lawsuit, styled Apache Corporation v. W&T Offshore, Inc., is currently pending in the United States District Court for the Southern District of Texas. Apache contends that W&T has failed to pay its proportional share of the costs associated with plugging and abandoning three wells that are subject to the JOA. We contend that the costs incurred by Apache are excessive and unreasonable. Apache seeks an award of actual damages, interest, court costs, and attorneys' fees. In February 2015, we made a payment to Apache for our net share of the amount that we believe was reasonable to plug and abandon the three wells. Our estimate of the potential exposure ranges from zero to $43.7 million (which is the amount claimed by Apache as of June 30, 2016). Such amount excludes potential interest, court costs and attorneys' fees. Trial on this case is set for October 17, 2016.

Insurance Claims. During the fourth quarter of 2012, underwriters of W&T's excess liability policies ("Excess Policies") (Indemnity Insurance Company of North America, New York Marine & General Insurance Company, Navigators Insurance Company, XL Specialty Insurance Company, National Liability & Fire Insurance Company ("Starr Marine") and Liberty Mutual Insurance Co.) filed declaratory judgment actions in the United States District Court for the Southern District of Texas (the "District Court") seeking a determination that our Excess Policies do not cover removal-of-wreck and debris claims arising from Hurricane Ike except to the extent we have first exhausted the limits of our Energy Package (defined as certain insurance policies relating to our oil and gas properties which includes named windstorm coverage) with only removal-of-wreck and debris claims. The court consolidated the various suits filed by the underwriters. In January 2013, we filed a motion for summary judgment seeking the court's determination that such Excess Policies do not require us to exhaust the limits of our Energy Package policies with only removal-of-wreck and debris claims. In July 2013, the District Court ruled in favor of the underwriters, adopting their position that the Excess Policies cover removal-of-wreck and debris claims only to the extent the limits of our Energy Package policies have been exhausted with removal-of-wreck and debris claims. We appealed the decision in the United States Court of Appeals for the Fifth Circuit (the "Fifth Circuit") and, in June 2014, the Fifth Circuit reversed the District Court's ruling and ruled in our favor. The underwriters filed three separate briefs requesting a rehearing or a certification to the Texas Supreme Court, all of which the Court denied. A brief was subsequently filed by one underwriter requesting a rehearing to the District Court of the Fifth Circuit's decision, which the District Court denied. Claims of approximately $43 million were filed, of which approximately $1 million was paid under the Energy Package and of which approximately $1 million was paid under our Comprehensive General Liability policy. One of the underwriters, Liberty Mutual Insurance Co., paid its portion of the settlement (approximately $5 million), in addition to a portion of interest owed. The other underwriters have not paid, and we filed a lawsuit in September 2014 against these underwriters for amounts owed, interest, attorney fees and damages. Subsequent to the filing of that lawsuit, Liberty Mutual Insurance Co. paid additional interest and Starr Marine has paid its portion ($5 million) of the first excess liability policy without interest. The lawsuit includes interest not paid by Starr Marine. The revised estimate of potential reimbursement is approximately $31 million, plus interest, attorney fees and damages, if any. Removal-of-wreck costs are recorded in Oil and natural gas properties and equipment on the Condensed Consolidated Balance Sheets and recoveries from claims made on these Excess Policies will be recorded as reductions in this line item, which will reduce our future depreciation, depletion, amortization and accretion (“DD&A”) rate.

Royalties. In 2009, the Company 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 the 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 IBLA. W&T's brief was filed in November 2014 and we expect the briefing before the IBLA to be completed in the second half of 2016.

The ONRR has publicly announced an "unbundling" initiative to review 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. In the second quarter of 2015, pursuant to the initiative, the Company received requests from the ONRR for additional data regarding the Company's transportation and processing allowances on natural gas production that is processed through a specific processing plant. The Company also received a preliminary determination notice from the ONRR asserting its preliminary determination that the Company's allocation of certain processing costs and plant fuel use at another processing plant were impermissibly allowed as deductions in the determination of royalties owed under Federal oil and gas leases. The Company intends to submit a response to the preliminary determination asserting the reasonableness of its own allocation methodology of such costs. These open ONRR unbundling reviews, and any further similar reviews, could ultimately result in an order for payment of additional royalties under the Company's Federal oil and gas leases for current and prior periods. The Company is not able to determine the likelihood or range of any additional royalties or, if and when assessed, whether such amounts would be material.

Notices of Proposed Civil Penalty Assessment. The Company currently has three open Incidents of Noncompliance ("INCs") issued by the BSEE, which have not been settled as of the filing of this Form 10-Q. The INC's were issued during 2015 and relate to three separate offshore locations with occurrence dates ranging from July 2012 to June 2014. The proposed civil penalties for these INCs total $7.1 million. The Company has accrued approximately $1.0 million, which is the Company's best estimate of the final settlement once all appeals have been exhausted. The Company has had recent success in appealing one of the BSEE's INCs. During the second quarter of 2016, the BSEE reconsidered and remanded their proposed civil penalty (dating from June 2014) following the Company's successful appeal to the IBLA that supported the position that there was no basis for civil penalty consideration in this matter. The decision released approximately $1.0 million of potential contingency liability. The Company's position is that the proposed civil penalties are excessive given the specific facts and circumstances related to these INCs.

Iberville School Board Lawsuit. In August, 2013, a citation was issued on behalf of plaintiffs, the State of Louisiana and the Iberville Parish School Board, in their suit against the Company (among others) in the 18th Judicial District Court for the Parish of Iberville, State of Louisiana. This case involves claims by the Iberville Parish School Board that this property has allegedly been contaminated or otherwise damaged by certain defendants' oil and gas exploration and production activities. The plaintiff's claims include assessment costs, restoration costs, diminution of property value, punitive damages, and attorney fees and expenses, of which were not quantified in the claim. We cannot currently estimate our potential exposure, if any, related to this lawsuit. We are currently, and intend to continue to vigorously defending this litigation.

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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. In addition, the BOEM considers all owners of record title and/or operating rights interest in an Outer Continental Shelf ("OCS") lease to be jointly and severally liable for the satisfaction of the supplemental bonding obligations and/or decommissioning obligations. Accordingly, we may be required to satisfy supplemental bonding obligations or decommissioning obligations of a defaulting owner of record title and/or operating rights interest in an OCS lease in which we are (or in some cases were) an owner of record title and/or operating rights interest in the same OCS lease. 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.

Contingent Liability Recorded. There were no material expenses recognized related to accrued and settled claims, complaints and fines for the six months ended June 30, 2016 and 2015. As of June 30, 2016 and December 31, 2015, we had no material amounts recorded in liabilities for claims, complaints and fines.

12. Subsequent Events

Commencement of Exchange Offer and Consent Solicitation. On July 25, 2016, we announced the commencement of an exchange offer and consent solicitation to certain eligible holders of our outstanding 8.50% Senior Notes due 2019 for up to (i) 62,100,000 shares of common stock, par value $0.00001 per share, (ii) $202.5 million aggregate principal amount of new secured notes due 2020 and (iii) $180.0 million aggregate principal amount of new unsecured notes due 2021. Interest for the new secured notes may be paid-in-kind at our option at a rate of 10.75% per annum for 18 months after issuance and is otherwise payable in cash at a rate of 9% per annum. Interest for the new unsecured notes may be paid-in-kind at our option at a rate of 10.00% per annum for 24 months after issuance and is otherwise payable in cash at a rate of 8.5% per annum. Concurrently with the exchange offer, the Company is soliciting consents from holders of the 8.50% Senior Notes to adopt certain proposed amendments to the current indenture.

The exchange offer is conditioned on the satisfaction or waiver of certain additional conditions, including, among other things, (i) shareholder approvals related to the increase in the number of authorized shares of the Company's common stock and the issuance of the shares in the exchange offer, which our majority stockholder, Tracy W. Krohn, has stated he intends to approve, (ii) receipt of requisite lender consents to an amendment to our bank credit facility to permit the exchange offer, which consents have been obtained subject to completion of definitive documentation, and (iii) a minimum of 95%, or $855.0 million, of the 8.50% Senior Notes being tendered as of the expiration date, together with requisite consents having been obtained, which tender condition may be waived, in our discretion, provided 85%, or $765.0 million, of the 8.50% Senior Notes are tendered as of the expiration date. To the extent less than 90% in principal amount of the 8.50% Senior Notes are validly tendered and accepted for exchange, the new unsecured notes will instead be issued as secured by third-priority liens on substantially all of our and our subsidiary guarantors' assets that secure our revolving bank credit facility. Consummation of the exchange offer is also conditioned upon the satisfaction or waiver by the Company of certain other conditions. The exchange offer for the 8.50% Senior Notes expires on September 1, 2016, subject to extension. The exchange offer and consent solicitation for the 8.50% Senior Notes may be amended, extended or terminated.

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An amendment to the Credit Agreement will become effective in the event of consummation of the current exchange offer and certain related transactions on or before October 31, 2016, including the issuance of a $75.0 million 1.5 Lien Term Loan, the net proceeds of which would be applied to reduce amounts outstanding on our revolving bank credit facility. The amendment also provides that, in the event it becomes effective, the borrowing base will be reaffirmed at $150.0 million and will not be subject to a scheduled or elective interim redetermination until April 1, 2017. The amendment will also revise various financial ratio covenants upon effectiveness as follows: (i) the Secured Debt Leverage Ratio will be eliminated, (ii) the First Lien Leverage Ratio will increased from 1.50 to 1.00 to 2.50 to 1.00 as of the end of each fiscal quarter with a stepdown to 2.00 to 1.00 beginning with the fiscal quarter ending September 30, 2017 and (iii) the Company will maintain an Asset Coverage Ratio of Total Proved PV-10 to borrowings and letters of credit outstanding under the revolving bank credit facility of 1.25 to 1.00 to be measured quarterly up to and including the quarter ending December 31, 2016.

New Capital Financing. We have entered into commitment papers with certain holders of the 8.50% Senior Notes to provide $75.0 million of additional capital through borrowings on a 1.5 Lien Term Loan, which financing commitment is contingent upon the consummation of the exchange offer described above. The 1.5 Lien Term Loan will be junior only to the revolving bank credit facility and certain other customary permitted liens and will be secured by a 1.5 priority lien on all assets granted to secure indebtedness under our revolving bank credit facility.

13. Supplemental Guarantor Information

Our payment obligations under the 8.50% Senior Notes, the 9.00% Term Loan and the Credit Agreement (see Note 5) 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 of the 8.50% Senior Notes 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 Sales provisions (as such terms are define in certain debt documents);

(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 Sales” 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 certain debt documents) 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. Transfers of property were made from the Parent Company to the Guarantor Subsidiaries. As these transfers were transactions between entities under common control, the prior period financial information has been retrospectively adjusted for comparability purposes, as prescribed under authoritative guidance. None of the adjustments had any effect on the consolidated results for the current or prior periods presented.

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

Condensed Consolidating Balance Sheet as of June 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$171,824	$—	$—	$171,824
Receivables:				
Oil and natural gas sales	2,626	32,215	—	34,841
Joint interest and other	20,145	—	—	20,145
Income taxes	104,801	—	(99,202)	5,599
Total receivables	127,572	32,215	(99,202)	60,585
Prepaid expenses and other assets	15,797	2,461	—	18,258
Total current assets	315,193	34,676	(99,202)	250,667
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,672,644	2,228,608	—	7,901,252
Furniture, fixtures and other	20,873	—	—	20,873
Total property and equipment	5,693,517	2,228,608	—	7,922,125
Less accum. depreciation, depletion and amortization	5,297,078	1,973,181	(3,970)	7,266,289
Net property and equipment	396,439	255,427	3,970	655,836
Deferred income taxes	6,305	2,158	—	8,463
Restricted deposits for asset retirement obligations	26,409	—	—	26,409
Income tax receivables	52,097	—	—	52,097
Other assets	384,408	283,212	(662,738)	4,882
Total assets	$1,180,851	$575,473	$(757,970)	$998,354
Liabilities and Shareholders' Deficit				
Current liabilities:				
Accounts payable	$85,708	$7,144	$—	$92,852
Undistributed oil and natural gas proceeds	18,751	1,908	—	20,659
Asset retirement obligations	72,906	18,390	—	91,296
Accrued liabilities	12,035	99,178	(99,202)	12,011
Total current liabilities	189,400	126,620	(99,202)	216,818
Long-term debt	1,345,051	—	—	1,345,051
Asset retirement obligations, less current portion	137,295	115,531	—	252,826
Other liabilities	345,879	—	(329,417)	16,462
Shareholders' deficit:				
Common stock	1	—	—	1
Additional paid-in capital	428,618	704,885	(704,885)	428,618
Retained earnings (deficit)	(1,241,226)	(371,563)	375,534	(1,237,255)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' deficit	(836,774)	333,322	(329,351)	(832,803)
Total liabilities and shareholders' deficit	$1,180,851	$575,473	$(757,970)	$998,354

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

Condensed Consolidating Balance Sheet as of December 31, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$85,414	$—	$—	$85,414
Receivables:				
Oil and natural gas sales	2,742	32,263	—	35,005
Joint interest and other	121,190	—	(99,178)	22,012
Total receivables	123,932	32,263	(99,178)	57,017
Prepaid expenses and other assets	25,375	1,504	—	26,879
Total current assets	234,721	33,767	(99,178)	169,310
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,682,793	2,219,701	—	7,902,494
Furniture, fixtures and other	20,802	—	—	20,802
Total property and equipment	5,703,595	2,219,701	—	7,923,296
Less accum. depreciation, depletion and amortization	5,258,563	1,822,273	(147,589)	6,933,247
Net property and equipment	445,032	397,428	147,589	990,049
Deferred income taxes	27,251	344	—	27,595
Restricted deposits for asset retirement obligations	15,606	—	—	15,606
Other assets	498,782	266,748	(760,068)	5,462
Total assets	$1,221,392	$698,287	$(711,657)	$1,208,022
Liabilities and Shareholders' Deficit				
Current liabilities:				
Accounts payable	$100,282	$9,515	$—	$109,797
Undistributed oil and natural gas proceeds	20,463	976	—	21,439
Asset retirement obligations	63,716	20,619	—	84,335
Accrued liabilities	11,922	99,178	(99,178)	11,922
Total current liabilities	196,383	130,288	(99,178)	227,493
Long-term debt	1,196,855	—	—	1,196,855
Asset retirement obligations, less current portion	173,105	120,882	—	293,987
Other liabilities	329,129	—	(312,951)	16,178
Shareholders' deficit:				
Common stock	1	—	—	1
Additional paid-in capital	423,499	704,885	(704,885)	423,499
Retained earnings (deficit)	(1,073,413)	(257,768)	405,357	(925,824)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' deficit	(674,080)	447,117	(299,528)	(526,491)
Total liabilities and shareholders' deficit	$1,221,392	$698,287	$(711,657)	$1,208,022

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

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$43,914	$ 55,741	$ —	$ 99,655
Operating costs and expenses:				
Lease operating expenses	19,254	17,368	—	36,622
Production taxes	370	—	—	370
Gathering and transportation	2,469	3,929	—	6,398
Depreciation, depletion, amortization and accretion	22,648	31,934	2,911	57,493
Ceiling test write-down of oil and natural gas properties	—	35,008	69,584	104,592
General and administrative expenses	7,360	8,875	—	16,235
Derivative loss	4,942	—	—	4,942
Total costs and expenses	57,043	97,114	72,495	226,652
Operating loss	(13,129)	(41,373)	(72,495)	(126,997)
Loss of affiliates	(40,765)	—	40,765	—
Interest expense:				
Incurred	29,735	38	—	29,773
Capitalized	(64)	(38)	—	(102)
Other expense, net	(24)	—	—	(24)
Loss before income tax benefit	(83,541)	(41,373)	(31,730)	(156,644)
Income tax benefit	(35,114)	(608)	—	(35,722)
Net loss	$(48,427)	$ (40,765)	$ (31,730)	$ (120,922)

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

Condensed Consolidating Statement of Operations for the Six Months Ended June 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$74,426	$ 102,944	$ —	$ 177,370
Operating costs and expenses:				
Lease operating expenses	44,199	36,892	—	81,091
Production taxes	896	—	—	896
Gathering and transportation	4,022	7,468	—	11,490
Depreciation, depletion and amortization	43,271	70,095	7,860	121,226
Ceiling test write-down of oil and natural gas properties	—	85,392	135,759	221,151
General and administrative expenses	13,973	18,705	—	32,678
Derivative loss	2,449	—	—	2,449
Total costs and expenses	108,810	218,552	143,619	470,981
Operating loss	(34,384)	(115,608)	(143,619)	(293,611)
Loss of affiliates	(113,794)	—	113,794	—
Interest expense:				
Incurred	57,430	157	—	57,587
Capitalized	(288)	(157)	—	(445)
Other expense, net	1,282	—	—	1,282
Loss before income tax benefit	(206,602)	(115,608)	(29,825)	(352,035)
Income tax benefit	(38,790)	(1,814)	—	(40,604)
Net loss	$(167,812)	$ (113,794)	$ (29,825)	$ (311,431)

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

Condensed Consolidating Statement of Operations for the Three Months Ended June 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$90,465	$ 58,601	$ —	$ 149,066
Operating costs and expenses:				
Lease operating expenses	30,104	15,026	—	45,130
Production taxes	1,000	—	—	1,000
Gathering and transportation	2,769	2,024	—	4,793
Depreciation, depletion, amortization and accretion	58,023	45,319	—	103,342
Ceiling test write-down of oil and natural gas properties	181,300	71,472		252,772
General and administrative expenses	10,856	8,901	—	19,757
Derivative loss	1,078	—	—	1,078
Total costs and expenses	285,130	142,742	—	427,872
Operating loss	(194,665)	(84,141)	—	(278,806)
Loss of affiliates	(54,548)	—	54,548	—
Interest expense:				
Incurred	25,322	794	—	26,116
Capitalized	(1,230)	(794)	—	(2,024)
Other expense, net	1,685	—	—	1,685
Loss before income tax benefit	(274,990)	(84,141)	54,548	(304,583)
Income tax benefit	(14,541)	(29,593)	—	(44,134)
Net loss	$(260,449)	$ (54,548)	$ 54,548	$ (260,449)

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

Condensed Consolidating Statement of Operations for the Six Months Ended June 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 167,808	$ 109,165	$ —	$ 276,973
Operating costs and expenses:				
Lease operating expenses	67,742	30,719	—	98,461
Production taxes	1,637	—	—	1,637
Gathering and transportation	5,334	4,283	—	9,617
Depreciation, depletion, amortization and accretion	129,374	99,435	—	228,809
Ceiling test write-down of oil and natural gas properties	371,995	141,167		513,162
General and administrative expenses	22,615	17,908	—	40,523
Derivative loss	1,078	—	—	1,078
Total costs and expenses	599,775	293,512	—	893,287
Operating loss	(431,967)	(184,347)	—	(616,314)
Loss of affiliates	(119,552)	—	119,552	—
Interest expense:				
Incurred	47,554	1,508	—	49,062
Capitalized	(2,299)	(1,508)	—	(3,807)
Other expense, net	1,683	—	—	1,683
Loss before income tax benefit	(598,457)	(184,347)	119,552	(663,252)
Income tax benefit	(82,913)	(64,795)	—	(147,708)
Net loss	$ (515,544)	$ (119,552)	$ 119,552	$ (515,544)

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

Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net loss	$ (167,812)	$ (113,794)	$ (29,825)	$ (311,431)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion, amortization and accretion	43,271	70,095	7,860	121,226
Ceiling test write-down of oil and natural gas properties	—	85,392	135,759	221,151
Debt issuance costs write-off/amortization of debt items	1,880	—	—	1,880
Share-based compensation	5,121	—	—	5,121
Derivative loss	2,449	—	—	2,449
Cash receipts on derivative settlements, net	4,746	—	—	4,746
Deferred income taxes	21,099	(1,814)	—	19,285
Loss of affiliates	113,794	—	(113,794)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	1,177	49	—	1,226
Joint interest and other receivables	1,763	—	—	1,763
Income taxes	(57,931)	—	—	(57,931)
Prepaid expenses and other assets	(9,405)	(17,424)	16,464	(10,365)
Asset retirement obligation settlements	(12,702)	(12,454)	—	(25,156)
Accounts payable, accrued liabilities and other	(783)	32,014	(16,464)	14,767
Net cash provided by (used in) operating activities	(53,333)	42,064	—	(11,269)
Investing activities:				
Investment in oil and natural gas properties and equipment	(8,600)	(9,112)	—	(17,712)
Changes in operating assets and liabilities associated with investing activities	(670)	(33,452)	—	(34,122)
Proceeds from sales of assets	1,000	500	—	1,500
Purchases of furniture, fixtures and other	(70)	—	—	(70)
Net cash used in investing activities	(8,340)	(42,064)	—	(50,404)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	340,000	—	—	340,000
Repayments of long-term debt – revolving bank credit facility	(192,000)	—	—	(192,000)
Other	83	—	—	83
Net cash provided by financing activities	148,083	—	—	148,083
Increase in cash and cash equivalents	86,410	—	—	86,410
Cash and cash equivalents, beginning of period	85,414	—	—	85,414
Cash and cash equivalents, end of period	$ 171,824	$ —	$ —	$ 171,824

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

Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net loss	$ (515,544)	$ (119,552)	$ 119,552	$ (515,544)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion, amortization and accretion	129,374	99,435	—	228,809
Ceiling test write-down of oil and natural gas properties	371,995	141,167	—	513,162
Debt issuance costs write-off/ amortization of debt items	2,432	—	—	2,432
Share-based compensation	5,708	—	—	5,708
Derivative loss	1,078	—	—	1,078
Deferred income taxes	(105,818)	(41,890)	—	(147,708)
Loss of affiliates	119,552	—	(119,552)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	18,710	(3,425)	—	15,285
Joint interest and other receivables	11,036	—	—	11,036
Income taxes	22,580	(22,905)	—	(325)
Prepaid expenses and other assets	(31,091)	94,890	(54,870)	8,929
Asset retirement obligations	(21,146)	(793)	—	(21,939)
Accounts payable, accrued liabilities and other	(74,370)	(513)	54,870	(20,013)
Net cash provided by (used in) operating activities	(65,504)	146,414	—	80,910
Investing activities:				
Investment in oil and natural gas properties and equipment	(25,313)	(125,681)	—	(150,994)
Changes in operating assets and liabilities associated with investing activities	(28,671)	(22,178)	—	(50,849)
Investment in subsidiary	(1,445)	—	1,445	—
Purchases of furniture, fixtures and other	(709)	—	—	(709)
Net cash used in investing activities	(56,138)	(147,859)	1,445	(202,552)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	194,000	—	—	194,000
Repayments of long-term debt – revolving bank credit facility	(381,000)	—	—	(381,000)
Issuance of 9.00% Term Loan	297,000	—	—	297,000
Debt issuance costs	(6,407)	—	—	(6,407)
Other	54	—	—	54
Investment from parent	—	1,445	(1,445)	—
Net cash provided by financing activities	103,647	1,445	(1,445)	103,647

Decrease in cash and cash equivalents	(17,995)	—	—	(17,995)
Cash and cash equivalents, beginning of period	23,666	—	—	23,666
Cash and cash equivalents, end of period	$ 5,671	$ —	$ —	$ 5,671

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"), which 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, 2015 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 with operations offshore in the Gulf of Mexico. We have grown through acquisitions, exploration and development and currently hold working interests in approximately 54 offshore fields in federal and state waters (50 producing and four fields capable of producing). We currently have under lease approximately 750,000 gross acres, with approximately 450,000 gross acres on the shelf and approximately 300,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. Our interest in fields, leases, structures and equipment are primarily owned by the parent company, W&T Offshore, Inc. and our wholly-owned subsidiary, W & T Energy VI, LLC.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for the first half of 2016 were comprised of 47.7% oil and condensate, 10.3% NGLs and 42.0% natural gas, determined using the energy equivalency ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price per one barrel oil equivalent ("Boe") for oil, NGLs and natural gas has differed significantly from time to time. In the first half of 2016, revenues from the sale of oil and NGLs made up 75.9% of our total revenues compared to 74.0% for the first half of 2015. For the first half of 2016, our combined total production was 9.1% lower than the first half of 2015 primarily due to lower natural gas production. For the first half of 2016, our total revenues were 36.0% lower than the first half of 2015 due primarily to significantly lower realized prices for oil, NGLs and natural gas. See Results of Operations – Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015 in this Item for additional information on our revenues and production.

On October 15, 2015, we sold our interests in the Yellow Rose onshore field in the Permian Basin to Ajax. Our interest in the field covered approximately 25,800 net acres. During the first half of 2015, the Yellow Rose field accounted for approximately 7% and 8% of our production and revenues, respectively. In connection with the sale, we retained a non-expense bearing ORRI equal to a variable percentage in production from the working interests sold, which percentage varies on a sliding scale from one percent for each month that the NYMEX prompt month contract trading price for light sweet crude oil is at or below $70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than $90.00 per barrel. Internal estimates of proved reserves at the date of the sale were 19.0 million barrels of oil equivalent ("MMBoe"), consisting of approximately 71% oil, 11% NGL and 18% natural gas. Including adjustments from an effective date of January 1, 2015, the adjusted sales price was $370.9 million of cash and the buyer assumed the ARO associated with our interests in the Yellow Rose field, which we had estimated at $6.9 million at the time of the sale, and the buyer assumed other liabilities of $1.1 million. We used a portion of the proceeds of the sale to repay all the outstanding borrowings under our revolving bank credit facility, while the remaining balance of approximately $98 million was added to available cash.

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. Beginning in the second half of 2014 and continuing through the second half of 2016, crude oil prices have fallen dramatically from a peak of over $100 per barrel for WTI in June 2014. In addition, prices of NGLs and natural gas have fallen significantly from 2014 levels. Commodity prices improved in the second quarter 2016 compared to the first quarter of 2016, but are still below 2015 average price levels. While U.S. production of crude oil and other petroleum liquids declined in the second quarter of 2016 from 2015, the overall market for the second quarter of 2016 remains in an oversupply position. Selected issues and data points are described below.

The U.S. Energy Information Administration ("EIA") estimates the worldwide crude oil and petroleum liquids supply will exceed demand in 2016, resulting in crude oil and other petroleum liquids inventories increasing by 0.9 million barrels per day. While the estimate for 2016 remains in an oversupply position, revised estimates for consumption were increased and has the market closer to being in balance for 2016 than previous estimates and being in balance for 2017. EIA estimates inventory builds in each quarter of 2016 and the first half of 2017, and forecasts the first inventory withdrawal occurring in the third quarter of 2017. Comparing the first half of 2016 to the first half of 2015, worldwide supply increased by 0.2 million barrels per day, primarily due to increases from OPEC, while U.S. supply decreased slightly between the two periods. EIA's estimate for 2016 has supply increasing over 2015 by 0.4 million barrels per day, with Iran accounting for most of the increase, partially offset by decreases primarily in the U.S. EIA's forecast for supply from OPEC does not assume any production cuts from collaborative agreements. EIA's estimate has consumption increasing in 2016 over 2015 by 1.4 million barrels per day, with the increases coming primarily from China and other Asian countries. EIA's consumption forecast incorporates only a slight downward revision for Europe as a result of uncertainty related to the United Kingdom leaving the European Union.

Per EIA, U.S. production of crude oil (excluding other petroleum liquids) decreased in the first half of 2016 by 5% compared to the first half of 2015. EIA's estimate for 2016 of U.S. crude oil production is a decrease of 9% from 2015, and for 2017, estimates a further decrease of 5% from 2016. As noted below, the number of rigs drilling for oil decreased dramatically in 2015 and further decreased through the first half of 2016.

During the first half of 2016, our average realized oil sales price was $32.80, down from $49.86 per barrel (34.2% lower) for the first half of 2015. The two primary benchmarks are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $39.55 per barrel for the first half of 2016, down from $53.25 per barrel (25.7% lower) for the first half of 2015. Brent crude average oil prices decreased to $39.80 per barrel for the first half of 2016, down from $57.84 per barrel (31.2% lower) for the first half of 2015. Our average realized oil sales price for the first half of 2016 differs from the benchmark crude prices due to premiums or discounts (referred to as differentials), crude quality adjustments, volume weighting and other factors. All of our oil for the first half of 2016 was produced offshore in the Gulf of Mexico and is characterized as Light Louisiana Sweet ("LLS"), Heavy Louisiana Sweet ("HLS"), Poseidon and others. WTI is frequently used to value domestically produced crude oil, and the majority of our oil production is priced using the spot price for WTI as a base price, then adjusted for the type and quality of crude oil and other factors. Similar to crude oil prices, the differentials for our offshore crude oil have also experienced volatility. For example, the monthly average differentials of WTI versus LLS, HLS and Poseidon for the first half of 2016 were a positive $1.82 and $1.02, and a negative $3.39 per barrel, respectively, compared to positive $4.45 and $3.72, and $0.15 per barrel, respectively, for the first half of 2015. The majority of our crude oil is priced similar to Poseidon and, therefore, is experiencing negative differentials. In addition, a few of our crude oil fields have a negative quality bank adjustment and production from two of our crude oil fields is being transported via barge, which is more expensive than pipeline transportation.

EIA projects average crude oil prices for WTI and Brent to decrease for the year 2016 compared to 2015 by approximately $5.00 per barrel and $10.00 per barrel, respectively, and to increase in 2017 by approximately $8.00 per barrel for each. Their estimate notes that the current values for futures and options indicate high volatility, and EIA estimates the range of WTI crude oil prices for 2016 of $35.00 to $67.00 per barrel at a 95% confidence interval. Other factors noted that may have a significant impact on future crude oil prices include the pace of economic growth and unplanned supply disruptions. In addition, the strength in the U.S. dollar relative to other currencies also has an impact on crude pricing. Because all barrels are traded in U.S. dollars, as the U.S. dollar gains strength, crude prices are lower in U.S. dollars but are more expensive in other currencies.

During the first half of 2016, our average realized NGLs sales price decreased 17.2% compared to the first half of 2015. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the first half of 2016, average prices for domestic ethane increased 2% and average domestic propane prices decreased 11% from the first half of 2015. Average price decreases for other domestic NGLs were 9% to 27%. Per EIA, production of ethane and propane increased in the first half of 2016 over the first half of 2015 by 14% and 5%, respectively. Ethane and propane inventory levels for the second quarter of 2016 were higher than the comparable quarter in 2015 by 29% and 2%, respectively. As long as the price ratio of crude oil to natural gas remains wide (as measured on a six to one energy equivalency), the production of NGLs may continue to be high relative to historical norms, which would in turn suggest continued weak prices, or possibly further price reductions, especially for the prices of ethane and propane. Many natural gas processing facilities have been and will likely continue re-injecting ethane back into the natural gas stream after processing due to insufficient ethane demand, which negatively impacts production and natural gas prices. Ethane demand is expected to increase in 2017 as petrochemical plants and expansion projects that consume ethane come online.

During the first half of 2016, our average realized natural gas sales price decreased 29.5% compared to the first half of 2015. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 26.6% lower in the first half of 2016 from the first half of 2015. 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. However, with the surplus of natural gas that has plagued the industry since 2012, natural gas prices have been weak and the fluctuations in prices have been limited to the lower end of the price range. Prices in the second quarter of 2016 increased from the first quarter of 2016, and prices in the last week of June were above the average prices for the first half of 2015. Heating degree days for the first quarter of 2016 were 18% lower than the first quarter of 2015, which had a direct impact on demand for natural gas during the winter season. The U.S. natural gas inventories at the end of June 2016 were approximately 20% higher than a year earlier and 23% higher than the five-year average. The natural gas injection season typically runs from April to October and EIA projects inventories at the end of the injection season to be the highest on record. U.S. consumption decreased in the first half of 2016 compared to the first half of 2015 by 2%, which was basically the same percentage decrease for supply. Consumption decreases came primarily from lower residential usage and partially offset by higher electric power usage. Excluding inventory net withdrawals, U.S. supply decreases were due to higher exports and lower imports, partially offset by higher production in the lower 48 states.

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

EIA projects natural gas prices to increase in the second half of 2016 compared to the first half of 2016, but lower for the full year of 2016 compared to 2015. U.S. supply is projected to be higher in 2016 compared to 2015 by 2% despite the decrease in drilling activity, and consumption is projected to increase by a similar amount even though it decreased for the first half of the year. Natural gas usage for power generation is expected to remain in the 33%-34% range for 2016 and 2017, which is approximately equivalent to 2015 due to lower natural gas prices compared to coal and new Federal regulations discouraging to coal usage.

During the first half of 2016, the number of rigs drilling for oil and natural gas in the U.S. was significantly below 2014 levels due to lower crude oil and natural gas prices. According to Baker Hughes, the oil rig count at December 2014, December 2015 and June 2016 was 1,482, 536 and 341, respectively. The number of rigs drilling for oil as of June 2016 was a seven-year low. The U.S. natural gas rig count at December 2014, December 2015 and June 2016 was 328, 162 and 89, respectively. The U.S. natural gas rig count as of June 2016 was a 29-year low (the extent of data provided by Baker Hughes). In the Gulf of Mexico, there were 54 rigs (42 oil and 12 natural gas) at the end of 2014; 25 rigs (20 oil and five natural gas) as of the end of 2015; and 18 rigs (15 oil and three natural gas) as of June 2016. The majority of working rigs in the Gulf of Mexico are currently “floaters” with very few jack-up rigs working.

As required by the full cost accounting rules, we perform our ceiling test calculation each quarter using the SEC pricing guidelines, which require using the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price adjusted for price differentials. The average price using the SEC required methodology at June 30, 2016 was $39.63 per barrel for WTI crude oil and $2.24 per MMBtu for Henry Hub natural gas before adjustments. Due to the decrease in the 12-month average price for both crude oil and natural gas, we recorded ceiling test write-downs of the carrying value of our oil and natural gas properties in the second quarter and first half of 2016 of $104.6 million and $221.2 million, respectively. For the first half and full year of 2015, the ceiling test write-downs were $513.2 million and $987.2 million, respectively. Incurrence of further write downs is dependent primarily on the price of crude oil and natural gas, but also is affected by quantities of proved reserves, future development costs and future lease operating costs.

We performed a pro-forma calculation to determine if a further ceiling test impairment write-down would be likely in the third quarter of 2016 based only on changes to prices using the assumptions that projected prices are the same as most recently published first-day-of-the month prices to compute a pro-forma 12-month average. In this pro-forma calculation, no changes were assumed for reserves from the June 30, 2016 levels other than price and no changes were assumed for other factors. The pro-forma calculation indicated that the ceiling-test write down for the second quarter of 2016 would have increased by $37 million and our estimated proved reserves would have decreased 0.1 MMBoe (less than 1%) under these assumptions. This pro-forma calculation may not be predictive, as other factors besides price will impact the ceiling test calculation.

On March 23, 2016, the banks reduced our borrowing base from $350.0 million to $150.0 million in connection with the spring borrowing base redetermination. Pursuant to the terms of the Credit Agreement, we repaid the borrowing base deficiencies to be in conformity with the limitation of the new borrowing base as of June 30, 2016.

During 2015, we were notified by the BOEM that the Company was no longer eligible for any exemptions set forth in the current regulations and procedures of the BOEM. In February and March 2016, we received several demands from the BOEM ordering that we provide additional security in the aggregate of $260.8 million. We filed appeals and received a stay on the effectiveness of the orders to August 31, 2016. We continue to have discussions with the BOEM regarding these matters. These matters are more fully discussed in the Liquidity and Capital Resources section of this Item II of this Form 10-Q.

Due to the deterioration of commodity prices and the outlook for the remainder of 2016, our 2016 capital expenditure budget is set well below prior year levels. Capital expenditures incurred for 2015 and 2014 were $231 million and $630 million, respectively. We have the flexibility to make this reduction to our 2016 capital expenditure budget because we have no long term rig commitments and no pressure from partners to drill or complete a well. Moreover, we expect our deepwater projects completed in 2015, combined with new production from our Ewing Bank 910 A-8 well, will partially offset normal production declines from existing wells during 2016 and the loss of production from the sale of Yellow Rose in the fourth quarter of 2015. However, unplanned downtime, pipeline maintenance, and well performance are factors leading to lower estimated production in 2016 from 2015. We do not expect to lose drilling opportunities at this spending level and have no significant lease expiration issues in 2016. In addition, our plans include spending $76 million in 2016 for ARO, which is an increase from $33 million spent on ARO in 2015.

On the cost side, we have seen relatively significant reductions in our lease operating expenses and general and administrative expenses as a result of our cost reduction programs, which include headcount and contractor usage reductions, combined with reduced rates from vendors for supplies, equipment and contract labor. These cost reduction programs and reduced supplier rates have also lowered capital expenditures, ARO settlements and ARO estimates.

On July 25, 2016, we announced commencement of an exchange offer and consent solicitation for our outstanding 8.50% Senior Notes. We expect to obtain in conjunction with the exchange offer a new 1.5 Lien Term Loan, which is described in the Liquidity and Capital Resources section of this Item 2.

Our short-term focus is on conserving capital and maintaining liquidity. In light of our limited access to capital and liquidity, we are not pursuing any significant acquisitions at this time and we are working on possible divestitures. 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, 2015, 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, 2016	2015	Change	%	Six Months Ended June 30, 2016	2015	Change	%
	(In thousands, except percentages and per share data)							
Financial:								
Revenues:								
Oil	$71,751	$108,079	$(36,328)	(33.6)%	$122,687	$189,606	$(66,919)	(35.3)%
NGLs	7,018	7,831	(813)	(10.4)%	12,013	15,277	(3,264)	(21.4)%
Natural gas	19,833	31,485	(11,652)	(37.0)%	40,103	68,660	(28,557)	(41.6)%
Other	1,053	1,671	(618)	(37.0)%	2,567	3,430	(863)	(25.2)%
Total revenues	99,655	149,066	(49,411)	(33.1)%	177,370	276,973	(99,603)	(36.0)%
Operating costs and expenses:								
Lease operating expenses	36,622	45,130	(8,508)	(18.9)%	81,091	98,461	(17,370)	(17.6)%
Production taxes	370	1,000	(630)	(63.0)%	896	1,637	(741)	(45.3)%
Gathering and transportation	6,398	4,793	1,605	33.5 %	11,490	9,617	1,873	19.5 %
Depreciation, depletion, amortization and accretion	57,493	103,342	(45,849)	(44.4)%	121,226	228,809	(107,583)	(47.0)%
Ceiling test write-down of oil and natural gas properties	104,592	252,772	(148,180)	(58.6)%	221,151	513,162	(292,011)	(56.9)%
General and administrative expenses	16,235	19,757	(3,522)	(17.8)%	32,678	40,523	(7,845)	(19.4)%
Derivative loss	4,942	1,078	3,864	NM	2,449	1,078	1,371	NM
Total costs and expenses	226,652	427,872	(201,220)	(47.0)%	470,981	893,287	(422,306)	(47.3)%
Operating loss	(126,997)	(278,806)	151,809	(54.4)%	(293,611)	(616,314)	322,703	(52.4)%
Interest expense, net of amounts capitalized	29,671	24,092	5,579	23.2 %	57,142	45,255	11,887	26.3 %
Other (income) expense, net	(24)	1,685	(1,709)	NM	1,282	1,683	(401)	(23.8)%
Loss before income tax benefit	(156,644)	(304,583)	147,939	(48.6)%	(352,035)	(663,252)	311,217	(46.9)%
Income tax benefit	(35,722)	(44,134)	8,412	(19.1)%	(40,604)	(147,708)	107,104	(72.5)%
Net loss	$(120,922)	$(260,449)	$139,527	(53.6)%	$(311,431)	$(515,544)	$204,113	(39.6)%
	$(1.58)	$(3.43)	$1.85	(53.9)%	$(4.07)	$(6.79)	$2.72	(40.1)%

Basic and diluted loss per common share	

NM – not meaningful

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	Three Months Ended June 30,				Six Months Ended June 30,			
	2016	2015	Change	% [2]	2016	2015	Change	% [2]
Operating: [1]								
Net sales:								
Oil (MBbls)	1,835	1,909	(74)	(3.9)%	3,740	3,803	(63)	(1.7)%
NGLs (MBbls)	451	408	43	10.5 %	809	851	(42)	(4.9)%
Natural gas (MMcf)	9,690	11,486	(1,796)	(15.6)%	19,761	23,835	(4,074)	(17.1)%
Total oil equivalent (MBoe)	3,901	4,231	(330)	(7.8)%	7,843	8,627	(784)	(9.1)%
Total natural gas equivalents (MMcfe)	23,404	25,388	(1,984)	(7.8)%	47,055	51,760	(4,705)	(9.1)%
Average daily equivalent sales (Boe/day)	42,864	46,497	(3,633)	(7.8)%	43,091	47,661	(4,570)	(9.6)%
Average daily equivalent sales (Mcfe/day)	257,186	278,984	(21,798)	(7.8)%	258,544	285,965	(27,421)	(9.6)%
Average realized sales prices:								
Oil ($/Bbl)	$39.11	$56.63	$(17.52)	(30.9)%	$32.80	$49.86	$(17.06)	(34.2)%
NGLs ($/Bbl)	15.56	19.18	(3.62)	(18.9)%	14.85	17.94	(3.09)	(17.2)%
Natural gas ($/Mcf)	2.05	2.74	(0.69)	(25.2)%	2.03	2.88	(0.85)	(29.5)%
Oil equivalent ($/Boe)	25.28	34.83	(9.55)	(27.4)%	22.29	31.71	(9.42)	(29.7)%
Natural gas equivalent ($/Mcfe)	4.21	5.81	(1.60)	(27.5)%	3.71	5.28	(1.57)	(29.7)%
Average per Boe ($/Boe):								
Lease operating expenses	$9.39	$10.67	$(1.28)	(12.0)%	$10.34	$11.41	$(1.07)	(9.4)%
Gathering and transportation	1.64	1.13	0.51	45.1 %	1.47	1.11	0.36	32.4 %
Production costs	11.03	11.80	(0.77)	(6.5)%	11.81	12.52	(0.71)	(5.7)%
Production taxes	0.09	0.24	(0.15)	(62.5)%	0.11	0.19	(0.08)	(42.1)%
DD&A	14.74	24.42	(9.68)	(39.6)%	15.46	26.52	(11.06)	(41.7)%
General and administrative expenses	4.16	4.67	(0.51)	(10.9)%	4.17	4.70	(0.53)	(11.3)%
	$30.02	$41.13	$(11.11)	(27.0)%	$31.55	$43.93	$(12.38)	(28.2)%
Average per Mcfe ($/Mcfe):								
Lease operating expenses	$1.56	$1.78	$(0.22)	(12.4)%	$1.72	$1.90	$(0.18)	(9.5)%
Gathering and transportation	0.27	0.19	0.08	42.1 %	0.24	0.19	0.05	26.3 %
Production costs	1.83	1.97	(0.14)	(7.1)%	1.96	2.09	(0.13)	(6.2)%
Production taxes	0.02	0.04	(0.02)	(50.0)%	0.02	0.03	(0.01)	(33.3)%
DD&A	2.46	4.07	(1.61)	(39.6)%	2.58	4.42	(1.84)	(41.6)%
General and administrative expenses	0.69	0.78	(0.09)	(11.5)%	0.69	0.78	(0.09)	(11.5)%

	$5.00	$6.86	$(1.86)	(27.1)%	$5.25	$7.32	$(2.07)	(28.3)%

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

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

Volume measurements:

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

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	Three Months Ended June 30,				Six Months Ended June 30,			
	2016	2015	Change	%	2016	2015	Change	%
Offshore - Wells drilled (gross)	—	2	(2)	(100.0)%	1	4	(3)	(75.0)%
Offshore - Productive wells drilled (gross)	—	2	(2)	(100.0)%	1	4	(3)	(75.0)%

The Company drilled onshore wells during 2015, which were included with the sale of the Yellow Rose field in October 2015 and were excluded in the table above as the Company has sold, relinquished or let expire essentially all onshore leasehold interest.

Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015

Revenues. Total revenues decreased $49.4 million, or 33.1%, to $99.7 million for the second quarter of 2016 as compared to the second quarter of 2015. Oil revenues decreased $36.3 million, or 33.6%, NGLs revenues decreased $0.8 million, or 10.4%, natural gas revenues decreased $11.7 million, or 37.0% and other revenues decreased $0.6 million. The decrease in oil revenues was attributable to a 30.9% decrease in the average realized sales price to $39.11 per barrel for the second quarter of 2016 from $56.63 per barrel for the second quarter of 2015, with sales volumes down 3.9%. The decrease in NGLs revenues was attributable to an 18.9% decrease in the average realized sales price to $15.56 per barrel for the second quarter of 2016 from $19.18 per barrel for the second quarter of 2015, partially offset by an increase of 10.5% in sales volumes. NGLs sales volumes were positively impacted by sales of ethane production (the ethane was sold as a product by the operator of the gas plant rather than reinjected into the natural gas stream). The decrease in natural gas revenues resulted from a 25.2% decrease in the average realized natural gas sales price to $2.05 per Mcf for the second quarter of 2016 from $2.74 per Mcf for the second quarter of 2015 and from a decrease of 15.6% in sales volumes. Overall, production declined 0.3 MMBoe (7.8%). We experienced increases in production at the Mississippi Canyon 698 field (“Big Bend”) and the Mississippi Canyon 782 field (“Dantzler”), which began production in the fourth quarter of 2015. Also, production increases were achieved at the Ewing Bank 910 field, the Main Pass 108 field and the Fairway field. Offsetting these production increases were production declines primarily from the sale of the Yellow Rose field (0.3 MMBoe); decreases at Ship Shoal 349 (“Mahogany”) due to pipeline and operational issues; natural production declines at Mississippi Canyon 243 (“Matterhorn”), Garden Banks 302 (“Power Play”), Mississippi Canyon 506 (“Wrigley”), and other fields; and production deferrals affecting various fields. Production deferrals, which occurred at Mahogany, East Cameron 321 A and other locations, were attributable to third-party pipeline outages, operational issues, and maintenance. We estimate production deferrals were 0.5 MMBoe during the second quarter of 2016 compared to 0.7 million MMBoe for the second quarter of 2015.

Revenues from oil and liquids as a percent of our total revenues were 79.0% for the second quarter of 2016 compared to 77.8% for the second quarter of 2015. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 39.8% for the second quarter of 2016 compared to 33.9% for the second quarter of 2015.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $8.5 million, or 18.9%, to $36.6 million in the second quarter 2016 compared to the second quarter of 2015. On a per Boe basis, lease operating expenses decreased to $9.39 per Boe during the second quarter of 2016 compared to $10.67 per Boe during the second quarter of 2015. On a component basis, base lease operating expenses decreased $3.8 million, workover expense decreased $2.3 million, insurance premiums decreased $1.6 million and facilities maintenance decreased $1.0 million. Base lease operating expenses decreased primarily due to lower costs from service providers and the sale of the Yellow Rose field; partially offset increases in expenses related to our new deepwater fields at Dantzler and Big Bend and by lower production handling fees (cost offsets) at our Matterhorn field. The decrease in workover costs was primarily due to the sale of the Yellow Rose field and casing work at Eugene Island 217 performed in 2015. The decrease in facilities maintenance was related to various activities that occurred in the 2015 period that did not reoccur in the 2016 period.

Production taxes. Production taxes decreased $0.6 million to $0.4 million for the second quarter of 2016 compared to the second quarter of 2015 primarily due to the sale of Yellow Rose. 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 increased $1.6 million to $6.4 million for the second quarter of 2016 compared to the second quarter of 2015 primarily due to new production increases at Big Bend and Dantzler, both of which began producing in the fourth quarter of 2015.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, decreased to $14.74 per Boe for the second quarter of 2016 from $24.42 per Boe for the second quarter of 2015. On a nominal basis, DD&A decreased to $57.5 million, (44.4%), for the second quarter of 2016 from $103.3 million for the second quarter of 2015. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2015 and the first quarter of 2016 (the second quarter 2016 ceiling test write-down will not affect the DD&A rate until the third quarter of 2016) and lower capital expenditures in relation to DD&A expense, which lowers the full-cost pool subject to DD&A. In addition, the proceeds from the sale of our Yellow Rose field reduced the full cost pool along with the removal of future development costs associated with the Yellow Rose field reserves. Other factors affecting the DD&A rate are lower future development costs on remaining reserves and lower proved reserves volumes.

Ceiling test write-down of oil and natural gas properties. For the second quarter of 2016, we recorded a non-cash ceiling test write-down of $104.6 million as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down is the result of decreases in prices for all three commodities we sell, which are crude oil, NGLs and natural gas. For the second quarter of 2015, the ceiling test write-down was $252.8 million. See Financial Statements and Supplementary Data – Note 1 - Basis of Presentation under Part I, Item 1 of this Form 10-Q, which provides a description of the ceiling test limit determination, and above under the section Overview in this Item regarding our prospects for a future ceiling test write-down.

General and administrative expenses (“G&A”). G&A decreased to $16.2 million, (17.8%), for the second quarter of 2016 from $19.8 million for the second quarter of 2015 primarily due to decreases in headcount related expense (salaries, benefits, and contractor expenses), partially offset by higher legal costs. G&A on a per BOE basis was $4.16 per Boe for the second quarter of 2016 compared to $4.67 per Boe for the second quarter of 2015.

Derivative loss. For the second quarter of 2016, there was a $4.9 million net derivative loss recorded for derivative contracts for crude oil and natural gas as increased prices for crude oil and natural gas resulted in reversal of previously recorded gains for open derivatives. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015, relating to 2015 and 2016 estimated production. For the second quarter of 2015, there was a $1.1 million net derivative loss recorded for derivative contracts for crude oil and natural gas.

Interest expense. Interest expense incurred was $29.8 million in the second quarter of 2016, up from $26.1 million in the second quarter of 2015. The increase was primarily attributable to increased borrowings on the revolving bank credit facility and the issuance of the 9.00% Term Loan in May 2015 with an aggregate principal amount of $300.0 million. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both periods. During the second quarter of 2016 and 2015, $0.1 million and $2.0 million, respectively, of interest costs were capitalized related to unevaluated oil and natural gas properties. The decrease is primarily attributable to the sale of the Yellow Rose field in the fourth quarter of 2015 and reclassifying certain unevaluated properties to the full cost pool during the second quarter of 2016 and the full year of 2015.

Other (income) expense, net. During the second quarter of 2015, the borrowing base on the revolving bank credit facility was reduced after the semi-annual redetermination and further reduced in conjunction with the issuance of the 9.00% Term Loan pursuant to the terms of the Credit Agreement. The reductions in the borrowing base resulted in a proportional reductions of $2.0 million in the unamortized debt issuance costs related to the revolving bank credit facility.

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Income tax benefit. Our income tax benefit for the second quarter of 2016 and 2015 was $35.7 million and $44.1 million, respectively, with the change attributable primarily to changes in the pre-tax loss and changes in the valuation allowance recorded for the respective periods. Our annualized effective tax rate for the second quarter of 2016 and 2015 was 22.8% and 14.5%, respectively, and differs from the federal statutory rate of 35% primarily due to recording and adjusting a valuation allowance related to federal and state deferred tax assets. During the three months ended June 30, 2016 and 2015, we recorded valuation allowances of $22.3 million and $62.9 million, respectively, related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to generate 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.

Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015

Revenues. Total revenues decreased $99.6 million, or 36.0%, to $177.4 million for the first half of 2016 as compared to the first half of 2015. Oil revenues decreased $66.9 million, or 35.3%, NGLs revenues decreased $3.3 million, or 21.4%, natural gas revenues decreased $28.6 million, or 41.6% and other revenues decreased $0.8 million. The decrease in oil revenues was attributable to a 34.2% decrease in the average realized sales price to $32.80 per barrel for the first half of 2016 from $49.86 per barrel for the first half of 2015, with sales volumes down by 1.7%. The decrease in NGLs revenues was attributable to a 17.2% decrease in the average realized sales price to $14.85 per barrel for the first half of 2016 from $17.94 per barrel for the first half of 2015 and a decrease of 4.9% in sales volumes. The decrease in natural gas revenues resulted from a 29.5% decrease in the average realized natural gas sales price to $2.03 per Mcf for the first half of 2016 from $2.88 per Mcf for the first half of 2015 and from a decrease of 17.1% in sales volumes. Overall, production declined 0.8 MMBoe (9.1%). We experienced increases in production at Big Bend and Dantzler, which began production in the fourth quarter of 2015. Also, production increases were achieved at the Ewing Bank 910 field, the Main Pass 108 field and the Mississippi Canyon 582 field (Medusa). Offsetting these production increases were production declines primarily from the sale of the Yellow Rose field (0.6 MMBoe); decreases at Mahogany due to pipeline and operational issues; natural production declines at Matterhorn, Power Play, Wrigley, and other fields; and production deferrals affecting various fields. Production deferrals, which occurred at multiple locations, were attributable to third-party pipeline outages, operational issues, and maintenance. We estimate production deferrals were 1.4 million MMBoe during the first half of 2016 compared to 1.2 million MMBoe for the first half of 2015.

Revenues from oil and liquids as a percent of our total revenues were 75.9% for the first half of 2016 compared to 74.0% for the first half of 2015. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 45.3% for the first half of 2016 compared to 36.0% for the first half of 2015.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $17.4 million, or 17.6%, to $81.1 million in the first half 2016 compared to the first half of 2015. On a per Boe basis, lease operating expenses decreased to $10.34 per Boe during the first half of 2016 compared to $11.41 per Boe during the first half of 2015. On a component basis, base lease operating expenses decreased $9.1 million, workover expense decreased $4.3 million, insurance premiums decreased $3.2 million and facilities maintenance decreased $1.0 million. Base lease operating expenses decreased primarily due to lower costs from service providers and the sale of the Yellow Rose field; partially offset by increases in expenses related to our new deepwater fields at Dantzler and Big Bend and lower production handling fees (cost offsets) at our Matterhorn field. The decrease in workover costs was primarily due to the sale of the Yellow Rose field and various activities that occurred in the 2015 period that did not reoccur in the 2016 period.

Production taxes. Production taxes decreased $0.7 million to $0.9 million for the first half of 2016 compared to the first half of 2015 primarily due to the sale of Yellow Rose. 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 increased $1.9 million to $11.5 million for the first half of 2016 compared to the first half of 2015 primarily due to new production increases at Big Bend and Dantzler, both of which began producing in the fourth quarter of 2015.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, decreased to $15.46 per Boe for the first half of 2016 from $26.52 per Boe for the first half of 2015. On a nominal basis, DD&A decreased to $121.2 million, (47.0%), for the first half of 2016 from $228.8 million for the first half of 2015. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2015 and the first quarter of 2016 (the second quarter 2016 ceiling test write-down will not affect the DD&A rate until the third quarter of 2016) and lower capital expenditures in relation to DD&A expense, which lowers the full-cost pool subject to DD&A. In addition, the proceeds from the sale of our Yellow Rose field reduced the full cost pool along with the removal of future development costs associated with the Yellow Rose field reserves. Other factors affecting the DD&A rate are lower future development costs on remaining reserves and lower proved reserves volumes.

Ceiling test write-down of oil and natural gas properties. For the first half of 2016, we recorded a non-cash ceiling test write-down of $221.2 million as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down is the result of decreases in prices for all three commodities we sell, which are crude oil, NGLs and natural gas. For the first half of 2015, the ceiling test write-down was $513.2 million. See Financial Statements and Supplementary Data – Note 1 - Basis of Presentation under Part I, Item 1 of this Form 10-Q, which provides a description of the ceiling test limit determination, and above under the section Overview in this Item regarding our prospects for a future ceiling test write-down.

General and administrative expense. G&A decreased to $32.7 million, (19.4%), for the first half of 2016 from $40.5 million for the first half of 2015 primarily due to decreases in headcount related expense (salaries, benefits, and contractor expenses), costs related to surety bonds (due to timing), partially offset by higher legal costs and professional services costs and higher medical claims. G&A on a per BOE basis was $4.17 per Boe for the first half of 2016 compared to $4.70 per Boe for the first half of 2015.

Derivative loss. For the first half of 2016, there was a $2.4 million net derivative loss recorded for derivative contracts for crude oil and natural gas as increased prices for crude oil and natural gas resulted in reversal of previously recorded gains for open derivatives. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015, relating to 2015 and 2016 estimated production. For the first half of 2015, there was a $1.1 million net derivative loss recorded for derivative contracts for crude oil and natural gas.

Interest expense. Interest expense incurred was $57.6 million in the first half of 2016, up from $49.1 million in the first half of 2015. The increase was primarily attributable to increased borrowings on the revolving bank credit facility and the issuance of the 9.00% Term Loan in May 2015 with an aggregate principal amount of $300.0 million. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both periods. During the first half of 2016 and 2015, $0.4 million and $3.8 million, respectively, of interest costs were capitalized related to unevaluated oil and natural gas properties. The decrease is primarily attributable to the sale of the Yellow Rose field in the fourth quarter of 2015 and reclassifying certain unevaluated properties to the full cost pool during the first half of 2016 and the full year of 2015.

Other (income) expense, net. During the first half of 2016 and the first half of 2015, the borrowing base on the revolving bank credit facility was reduced. The reductions in the borrowing base resulted in proportional reductions of $1.4 million and $2.0 million, respectively, in the unamortized debt issuance costs related to the revolving bank credit facility.

Income tax benefit. Our income tax benefit for the first half of 2016 and 2015 was $40.6 million and $147.7 million, respectively, with the change attributable primarily to changes in the pre-tax loss and changes in the valuation allowance recorded for the respective periods. Our annualized effective tax rate for the first half of 2016 and 2015 was 11.5% and 22.3%, respectively, and differs from the federal statutory rate of 35% primarily due to recording and adjusting a valuation allowance related to federal and state deferred tax assets. During the first half of 2016 and 2015, we recorded valuation allowances of $82.2 million and $85.4 million, respectively, related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses 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.

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 with cash on hand, net cash provided by operating activities, sales of property, securities offerings and bank borrowings. These sources of liquidity have historically been sufficient to fund our ongoing cash requirements.

Due to the continued weakness of commodity prices, we expect our future revenues, earnings, liquidity and ability to invest in future reserve growth to continue to be constrained. Other potential negative impacts of such price weakness include:

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

As a result of the potential for these events, we engaged legal and financial advisors to assist the Board of Directors and our management team to evaluate the various alternatives available to us and our pursuit of the course of action described below.

Commencement of Exchange Offer and Consent Solicitation. On July 25, 2016, we announced the commencement of an exchange offer (the “Exchange Offer”) and consent solicitation to certain eligible holders of our outstanding 8.50% Senior Notes (defined as “Existing Notes” in the Exchange Offer) for a maximum (assuming all outstanding principal is tendered) of (i) 62,100,000 shares of common stock, par value $0.00001 per share, of the Company (the “Shares”), (ii) $202.5 million aggregate principal amount of our new Senior Second Lien PIK Toggle Notes due 2020 (the “New Second Lien Notes”) and (iii) $180.0 million aggregate principal amount of our new Senior PIK Toggle Notes due 2021 (the “New Unsecured Notes”), together with the New Second Lien Notes, the “New Notes” and, together with the Shares (the “New Securities”). Concurrently with the Exchange Offer, the Company is soliciting consents from holders of the Existing Notes to adopt certain proposed amendments to the indenture under which the Existing Notes were issued.

The total consideration includes a premium of $25 per $1,000 principal amount for tendering by August 8, 2016. Eligible holders tendering their Existing Notes after August 8, 2016 and by September 1, 2016 (the “Expiration Date”) will receive the offer excluding the premium. Eligible holders of Existing Notes accepted for exchange will also receive a cash payment equal to the accrued and unpaid interest in respect of such Existing Notes from June 15, 2016 (the most recent interest payment date) to, but not including, the date the exchange is settled (the “Settlement Date”). Interest on the New Notes will accrue from the Settlement Date.

The Exchange Offer is conditioned on the satisfaction or waiver of certain additional conditions, including, among other things, (i) shareholder approvals related to the increase in the number of authorized shares of the Company’s common stock and the issuance of the Shares in the Exchange Offer, which our majority stockholder, Tracy W. Krohn, has stated he intends to approve, (ii) receipt of requisite lender consents to an amendment to our bank credit facility to permit the Exchange Offer, which consents have been obtained subject to completion of definitive documentation, and (iii) a minimum of 95%, or $855.0 million, of the Existing Notes being tendered as of the Expiration Date, together with requisite consents having been obtained, which tender condition may be waived, in our discretion, provided at least 85%, or $765.0 million, of the Existing Notes are tendered as of the Expiration Date. To the extent less than 90% in principal amount of the Existing Notes are validly tendered and accepted for exchange, the New Unsecured Notes will instead be issued as secured by third-priority liens on substantially all of our and our subsidiary guarantors' assets that secure our revolving bank credit facility. Consummation of the Exchange Offer is also conditioned upon the satisfaction or waiver by the Company of certain other conditions. The Exchange Offer and consent solicitation for the Existing Notes may be amended, extended or terminated. The Exchange Offer and consent solicitation is only being made to holders of the Existing Notes who complete and return an eligibility form confirming that they are (1) "qualified institutional buyers" within the meaning of Rule 144A under the Securities Act of 1933, as amended (the "Securities Act") or (2) not "U.S. persons" and are outside of the United States within the meaning of Regulation S under the Securities Act (such persons, "eligible holders").

On July 25, 2016, our obligations under a support agreement (the "Support Agreement"), with certain holders of Existing Notes became effective. Pursuant to the Support Agreement, the supporting noteholders have agreed to tender approximately 63.1% of the $900 million aggregate principal amount of the outstanding Existing Notes. Although holders of 63.1% of the principal amount of our 8.50% Senior Notes have agreed to support the Exchange Offer as proposed, there is no assurance the Exchange Offer will be completed as proposed.

The New Securities offered by us have not been registered under the Securities Act, or any state securities laws and, unless so registered, may not be offered or sold in the United States except pursuant to an applicable exemption from the registration requirements of the Securities Act and applicable state securities laws. The Exchange Offer and consent solicitation is not being made to holders of Existing Notes in any jurisdiction in which the making or acceptance thereof would not be in compliance with the securities, blue sky or other laws of such jurisdiction.

If the Exchange Offer, which expires September 1, 2016 subject to extension, is consummated under currently proposed terms with 95% of the 8.50% Senior Notes tendered by the date to qualify for the premium, the principal amount of our outstanding indebtedness would be reduced by $855.0 million. In exchange, $192.4 million principal amount of New Second Lien Notes would be issued; $171.0 principal amount of New Unsecured Notes would be issued; and 59.0 million shares of our common stock would be issued to exchanging holders.

An amendment to the Credit Agreement will become effective in the event of consummation of the current exchange offer and certain related transactions on or before October 31, 2016, including the issuance of a $75.0 million 1.5 Lien Term Loan, the net proceeds of which would be applied to reduce amounts outstanding on our revolving bank credit facility. The amendment also provides that, in the event it becomes effective, the borrowing base will be reaffirmed at $150.0 million and will not be subject to a scheduled or elective interim redetermination until April 1, 2017. The amendment will also revise various financial ratio covenants upon effectiveness as follows: (i) the Secured Debt Leverage Ratio will be eliminated, (ii) the First Lien Leverage Ratio will increased from 1.50 to 1.00 to 2.50 to 1.00 as of the end of each fiscal quarter with a stepdown to 2.00 to 1.00 beginning with the fiscal quarter ending September 30, 2017 and (iii) the Company will maintain an Asset Coverage Ratio of Total Proved PV-10 to borrowings and letters of credit outstanding under the revolving bank credit facility of 1.25 to 1.00 to be measured quarterly up to and including the quarter ending December 31, 2016.

In addition, the Company and certain holders of the Existing Notes entered into commitment papers whereby such holders agreed to provide $75.0 million in additional capital through borrowings under a 1.5 Lien Term Loan entered into on or around the same date as the consummation of the Exchange Offer, which financing is contingent upon consummation of the Exchange Offer and subject to certain terms and conditions. The 1.5 Lien Term Loan will be junior only to the revolving bank credit facility and certain other customary permitted liens and will be secured by a 1.5 priority lien on all assets granted to secure indebtedness under our revolving bank credit facility.

If we are unable to successfully consummate the Exchange Offer and address our near term liquidity needs, we may be unable to satisfy our future debt service obligations, meet other financial obligations and comply with the debt covenants governing our indebtedness, and we may seek relief under the U.S. Bankruptcy Code, which such relief may include: (i) seeking bankruptcy court approval for the sale or sales of some, most or substantially all of our assets and a subsequent liquidation of the remaining assets in the bankruptcy case; (ii) pursuing a plan of reorganization or (iii) seeking another form of bankruptcy relief, all of which involve uncertainties, potential delays and litigation risks.

BOEM Matters. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or post surety bonds or other acceptable financial assurances that such decommissioning obligations will be satisfied. Prior to 2015, we were partially exempt from providing such financial assurances under our corporate structure. The significant and sustained decline in crude oil and natural gas prices, however, has resulted in the Company no longer meeting the relevant financial strength and reliability criteria for such exemptions set forth in the current regulations and procedures of the BOEM. As a result, we were notified by the BOEM in 2015 that the Company was no longer eligible for any exemption from providing financial assurances to the BOEM. In February and March 2016, we received several demands from the BOEM ordering that we provide additional security in the aggregate of $260.8 million, with amounts specified with respect to certain designated leases, RUE and ROW. We have filed appeals with the IBLA regarding four of the BOEM orders - specifically the February order that required W&T to post a total of $159.8 million in additional security and three March orders requiring $101.0 million in additional security. The IBLA, acknowledging that the BOEM and the Company were seeking to resolve the BOEM orders through settlement discussions, stayed the effectiveness of the orders until June 30, 2016. Because settlement discussions were ongoing, on June 30, 2016, the IBLA again stayed the effectiveness of the orders until August 31, 2016. We continue to have discussions with the BOEM and its sister agency, the BSEE, in an effort to seek an acceptable resolution of the orders.

In July 2016, effective September 12, 2016, the BOEM issued Notice to Lessee (“NTL”) #2016-N01, related to obligations for decommissioning activities on the OCS, to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional security may be required for OCS leases, ROW and RUE. This NTL supersedes and replaces NTL 2008-N07. Among other things, the NTL eliminates the “waiver exemption” currently allowed by the BOEM, whereby lessees on the OCS meeting certain financial strength and reliability criteria are exempted from posting bonds or other acceptable financial assurances for such lessee’s decommissioning obligations. Under the new NTL, qualifying operators may self-insure for only an amount that is no more than 10% of their tangible net worth. In addition, the NTL implements a phase-in period for establishing compliance with additional security obligations for certain properties, whereby lessees may seek compliance with its additional security requirements under a “tailored plan” that is approved by the BOEM and would require securing phased in compliance in three approximately equal installments during a one-year period from the date of the BOEM approval of the tailored plan. Additional security for sole liability properties (those leases, ROWs or RUEs where there are no co-lessees or other grant holders or prior interest holders who may be liable to the BOEM) may not be phased in.

On July 14, 2016, BOEM issued an implementation timeline with respect to NTL #2016-N01, setting forth a timeline for lessees to submit a self-insurance request, for BOEM to send out proposal letters outlining required additional security, for BOEM to send out the order letters, for lessees to submit a tailored plan and for lessees to provide additional security. Implementation of this new NTL could result in us having to obtain additional bonds or other financial assurances and having to post collateral to obtain such additional bonds or other financial assurances. We believe our discussions with BOEM are consistent with a tailored arrangement under NTL #2016-N01 and we remain hopeful that our negotiations with the BOEM will result in an acceptable tailored plan with the BOEM. However if those negotiations do not result in an acceptable tailored plan and if we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition.

See “Risk Factors — We may be unable to provide the financial assurances demanded by the BOEM to cover our lease decommissioning obligations in the amounts and under the time periods required by the BOEM, either under the current rules or new rules that may be proposed. If extensions and modifications to the BOEM’s current or future demands are needed and cannot be obtained, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases” under Part II, Item 1A of this Form 10-Q.

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

The issuance of any additional surety bonds or other security to satisfy the BOEM orders, any 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 the creation of escrow accounts.

Cash Flow and Working Capital. Net cash used in operating activities for the first half of 2016 was $11.3 million and net cash provided by operating activities for the first half of 2015 was $80.9 million. Cash flows from operating activities, before changes in working capital, ARO settlements and adjusted for income taxes, (which are primarily non-cash due to our pre-tax loss position), were a positive $6.5 million in the first half of 2016, a decrease of $81.1 million compared to the $87.6 million generated during the first half of 2015. The significant reduction in cash flows excluding working capital, ARO settlements and income tax adjustment was primarily due to lower realized prices for all our commodities - oil, NGLs and natural gas and lower production volumes, partially offset by lower operating expenses. Our combined average realized sales price per Boe decreased 29.7%, which lowered revenues $83.1 million (83.4% of the total change in revenues). Combined volumes on a Boe basis decreased 9.1%, which lowered revenues by $15.6 million.

The changes in working capital (excluding income taxes) and ARO settlements decreased operating cash flows by $17.8 million in the first half of 2016. Major causes were settlements of ARO liabilities of $25.2 million and collateral deposits of $10.0 million, partially offset by changes in accounts payable and accrued liabilities of $14.8 million.

Net cash used in investing activities during the first half of 2016 and 2015 was $50.4 million and $202.6 million, respectively, which represents our investments in oil and gas properties and equipment. There were no acquisitions of significance during either period. Investments in oil and natural gas properties on an accrual basis in the first half of 2016 were $17.7 million compared to $151.0 million in the first half of 2015. The majority of expenditures during the first half of 2016 related to investments in the deepwater. In addition, adjustments from working capital changes associated with investing activities used net cash of $34.1 million in the first half of 2016 compared to net cash usage of $50.8 million in the first half of 2015. Both of these amounts represent cash expenditures in the year following the work, and accrual of the cost for accounting purposes occurred in the period the work was performed.

Net cash provided by financing activities for the first half of 2016 and 2015 was $148.1 million and $103.6 million, respectively. The net cash provided for the first half of 2016 was attributable to net borrowings on the revolving bank credit facility. The net cash provided for the first half of 2015 was attributable to the issuance of the 9.00% Term Loan, partially offset by repayments on the revolving bank credit facility.

Credit Agreement and Long-Term Debt. On March 23, 2016, the banks reduced our borrowing base from $350.0 million to $150.0 million in connection with the spring borrowing base redetermination. Pursuant to the terms of the Credit Agreement, we repaid the borrowing base deficiencies to be in conformity with the limitation of the new borrowing base as of June 30, 2016.

At June 30, 2016, $148.0 million was outstanding under our revolving bank credit facility compared to zero at December 31, 2015. During the first half of 2016, the outstanding borrowings on the revolving bank credit facility ranged from zero to $340.0 million. At June 30, 2016 and December 31, 2015, $900.0 million in aggregate principal amount of our 8.50% Senior Notes and $300.0 million in aggregate principal amount of our 9.00% Term Loan were outstanding.

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 spring redetermination occurred in March 2016, which is discussed above. The lenders and the Company have the option for an additional redetermination every year. 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, the 8.50% Senior Notes and the 9.00% Term Loan as of June 30, 2016. See Financial Statements - Note 5 – Long-Term Debt under Part I, Item 1 of this Form 10-Q for additional information.

Derivative Financial Instruments. From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of June 30, 2016, we had outstanding open derivatives for crude oil and natural gas. These derivatives provide downside protection against a portion of our remaining 2016 production and will provide cash inflows when crude oil or natural gas prices average below $40.00 per barrel and $2.25 per MMBtu, respectively, in a month. See Financial Statements - Note 4 - Derivative Financial Instruments under Part I, Item 1 of this Form 10-Q for additional information.

Insurance Claims and Insurance Coverage. During 2008, Hurricane Ike caused substantial property damage. Substantially all the costs related to Hurricane Ike have been incurred and we submitted claims under our insurance policies effective at that time, of which $161.2 million has been collected through December 31, 2015. In June 2014, the Fifth Circuit reversed a lower court's ruling in holding that our Excess Policies cover removal-of-wreck and debris claims arising from Hurricane Ike, even though we exhausted the limits of our Energy Package with non-removal-of-wreck and debris claim. Several of the underwriters have not paid us amounts we claim are due under such Excess Policies in accordance with the Fifth Circuit ruling. We filed a lawsuit in September 2014 against certain underwriters for amounts owed, interest, attorney fees and damages. We subsequently received reimbursement from certain underwriters of the Excess Policies of approximately $10 million. We believe we are still owed additional reimbursement of removal-of-wreck costs of approximately $31 million, plus interest, attorney fees and damages, if any. See Financial Statements - Note 11 - Contingencies under Part I, Item 1 of this Form 10-Q for additional information.

We currently carry multiple layers of insurance coverage in our Energy Package 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. We carry named windstorm coverage of $150.0 million for a total loss only ("TLO") on our Mahogany platform (Ship Shoal 349) and do not have named windstorm coverage on any other of our properties. The operational and named windstorm coverages described above are effective until June 1, 2017. Coverage for pollution causing a negative environmental impact is provided under the well control and named windstorm sections of the policy.

Our general and excess liability policies are effective until May 1, 2017 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 in May 2016, and our Energy Package in June 2016, our insurers may not continue to offer this type and level of coverage to us in the future, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurers will not pay our claims. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

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

	Six Months Ended June 30,	
	2016	2015
	(In thousands)	
Exploration (1)	$2,108	$40,235
Development (1)	13,765	99,149
Seismic, capitalized interest, and other	1,839	11,610
Acquisitions and investments in oil and gas property/equipment	$17,712	$150,994

(1) Reported geographically in the subsequent table.

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The following table presents our exploration and development capital expenditures on an accrual basis geographically:

	Six Months Ended June 30, 2016	2015
	(In thousands)	
Conventional shelf	$7,466	$9,321
Deepwater	8,514	117,748
Deep shelf	(107)	—
Onshore	—	12,315
Exploration and development capital expenditures	$15,873	$139,384

Our capital expenditures for the first half of 2016 were financed by cash flow from operating activities, sales of properties, borrowings on our revolving bank credit facility and cash on hand.

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

		Six Months Ended June 30, 2016		2015	
		Gross	Net	Gross	Net
Development wells -	Productive	—	—	—	—
Exploration wells -	Productive	1	0.5	4	0.7
Total wells		1	0.5	4	0.7

There were no unproductive (dry holes) during either period presented. The Company drilled onshore wells during 2015, which were included with the sale of the Yellow Rose field in October 2015 and were excluded in the table above as the Company has sold, relinquished or let expire essentially all onshore leasehold interest.

Exploration Activities. During the first quarter of 2016, the Ewing Bank 954 A-8 exploration well, which is part of the Ewing Bank 910 field, was completed and began producing on March 1, 2016. Subsequent to March 31, 2016, we had no wells being drilled. In 2015, we had one offshore well where drilling was deferred and the rig continues to be stacked on location.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. As previously discussed, in 2015 we sold our interest in the Yellow Rose field for $370.9 million cash after adjustments, reduced related ARO for $6.9 million and transferred the obligation of other related liabilities of $1.1 million. See Financial Statements - Note 2 – Divestitures under Part I, Item 1 of this Form 10-Q for additional information.

Capital Expenditure Budget for 2016. Because of the continued weak commodity prices and the outlook for the remainder of 2016, our capital expenditure budget for 2016 remains well below expenditures in prior years. In light of our limited access to capital and liquidity, we are not pursuing any significant acquisitions at this time. See the Overview section in this Item for additional information.

Income Taxes. During the first half of 2016, we made income tax payments of $0.3 million and received $2.3 million of refunds. During the first half of 2015, we did not make any income tax payments nor receive any refunds of significance. For the remainder of 2016, we expect that a substantial portion of our income tax will be deferred and payments, if any, will be primarily related to state taxes.

As of June 30, 2016, we recorded a current income tax receivable of $5.6 million and non-current income tax receivables of $52.1 million. For the current income tax receivable, the amount is comprised principally of an NOL claim for 2015 carried back to 2005 filed on Form 1139, Corporation Application for Tentative Refund. For the net amount classified as non-current income tax receivables, our NOL claims for the years 2012, 2013 and 2014 were carried back to the years 2003, 2004, 2007, 2010 and 2011 filed on Form 1120X, U.S. Corporation Income Tax Return. These carryback claims are made pursuant to IRC Section 172(f) which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. The refund claims filed on Form 1120X will require a review by the Congressional Joint Committee on Taxation and are accordingly classified as non-current.

We have $181.9 million of Federal net operating loss carryforwards (tax basis) available to offset future federal taxable income in 2016 and forward. We also have $33.9 million of alternative minimum tax credit carryforwards (tax basis) available to be utilized in 2016 and forward.

Dividends. During the first half of 2016 and the full year of 2015, we did not pay any dividends and a suspension of dividends remains in effect.

Asset Retirement Obligations. Each quarter, we review and revise our ARO estimates. Our ARO at June 30, 2016 and December 31, 2015 were $344.1 million and $378.3 million, respectively. Our estimate of ARO spending for the July 2016 to June 2017 time period is $91.3 million. As each of these estimates are for work to be performed in the future, and in the case of our non-current ARO, are for many years in the future, actual expenditures could be substantially different than our estimates. See our Annual Report on Form 10-K for the year ended December 31, 2015, Item 1A, Risk Factors, for additional information.

Contractual Obligations. Updated information on certain contractual obligations is provided in Financial Statements – Note 3 – Asset Retirement Obligations, Note 5 – Long-Term and Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q. As of June 30, 2016, drilling rig commitments were approximately $3.3 million compared to $7.0 million as of December 31, 2015. The current drilling rig commitments relate primarily to demobilization obligations. Except for scheduled utilization, other contractual obligations as of June 30, 2016 did not change materially from the disclosures in Management's Discussion and Analysis of Financial Condition and Results of Operations, of our Annual Report under Part II, Item 7 on Form 10-K for the year ended December 31, 2015.

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, 2015. 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 first half of 2016 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, 2015. 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, 2015.

Commodity Price Risk. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil, NGLs and natural gas, which fluctuate widely. Oil, NGLs and natural gas price declines have adversely affected our revenues, net cash provided by operating activities and profitability and could have further impact on our business in the future. As of June 30, 2016, we had open derivative contracts related to a portion of estimated production for the remainder of 2016. We historically have not designated our commodity derivatives as hedging instruments and any future derivative commodity contracts are not expected to be designated as hedging instruments. Use of these contracts may reduce the effects of volatile oil prices, but they also may limit future income from favorable price movements. See Financial Statements - Note 4 - Derivative Financial Instruments under Part I, Item 1 of this Form 10-Q for additional information.

Interest Rate Risk. As of June 30, 2016, we had $148.0 million outstanding on our revolving bank credit facility. The revolving bank credit facility has a variable interest rate, which is primarily impacted by the rates for the LIBOR and the margin, which ranges from 2.25% to 3.25% depending on the amount outstanding. As of June 30, 2016, 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 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, 2016, 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, 2016, there was no change in our internal control over financial reporting that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q for information on various legal matters.

Item 1A. Risk Factors

Investors should carefully consider the risk factors included under Part I, Item 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2015, together with all of the other information included in this document, in our Annual Report on Form 10-K and in our other public filings, press releases and discussions with our management.

The potential effects of the continued weakness in crude oil prices are discussed under Part I, Item 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2015 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, 2015, except as set forth below.

We may be unable to provide the financial assurances demanded by the BOEM to cover our lease decommissioning obligations in the amounts and under the time periods required by the BOEM, either under the current rules or new rules that may be proposed. If extensions and modifications to the BOEM's current or future demands are needed and cannot be obtained, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or post surety bonds or other acceptable financial assurances that such decommissioning obligations will be satisfied. Prior to 2015, we were partially exempt from providing such financial assurances under our corporate structure. The significant and sustained decline in crude oil and natural gas prices, however, has resulted in the Company no longer meeting the relevant financial strength and reliability criteria for such exemptions set forth in the current regulations and procedures of the BOEM. As a result, we were notified by the BOEM in 2015 that the Company was no longer eligible for any exemption from providing financial assurances to the BOEM.

In February and March 2016, we received several demands from the BOEM ordering the Company to secure financial assurances in the form of additional security in the aggregate of $260.8 million, with amounts specified with respect to certain designated leases, rights of use and easement and rights of way. We have filed appeals with the IBLA regarding four of the BOEM orders—specifically the February order requiring the Company to post a total of $159.8

million in additional security and three March orders requiring $101.0 million in additional security. The IBLA, acknowledging that the BOEM and the Company were seeking to resolve the BOEM orders through settlement discussions, stayed the effectiveness of the orders until June 30, 2016. Because settlement discussions were ongoing, on June 30, 2016, the IBLA again stayed the effectiveness of the orders until August 31, 2016. We continue to have discussions with the BOEM and its sister agency, the BSEE, in an effort to seek an acceptable resolution of the orders.

In July 2016, effective September 12, 2016, the BOEM issued NTL #2016-N01, related to obligations for decommissioning activities on the OCS, to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional security may be required for OCS leases, ROW and RUE. This NTL supersedes and replaces NTL 2008-N07. Among other things, the NTL eliminates the "waiver exemption" currently allowed by the BOEM, whereby lessees on the OCS meeting certain financial strength and reliability criteria are exempted from posting bonds or other acceptable financial assurances for such lessee's decommissioning obligations. Under the new NTL, qualifying operators may self-insure for only an amount that is no more than 10% of their tangible net worth. In addition, the NTL implements a phase-in period for establishing compliance with additional security obligations for certain properties, whereby lessees may seek compliance with its additional security requirements under a "tailored plan" that is approved by the BOEM and would require securing phased in compliance in three approximately equal installments during a one-year period from the date of the BOEM approval of the tailored plan. Additional security for sole liability properties (those leases, ROWs or RUEs where there are no co-lessees or other grant holders or prior interest holders who may be liable to the BOEM) may not be phased in.

On July 14, 2016, BOEM issued an implementation timeline with respect to NTL #2016-N01, setting forth a timeline for lessees to submit a self-insurance request, for BOEM to send out proposal letters outlining required additional security, for BOEM to send out the order letters, for lessees to submit a tailored plan and for lessees to provide additional security. Implementation of this new NTL could result in us having to obtain additional bonds or other financial assurances and having to post collateral to obtain such additional bonds or other financial assurances. We believe our discussions with BOEM are consistent with a tailored arrangement under NTL #2016-N01 and we remain hopeful that our negotiations with the BOEM will result in an acceptable tailored plan with the BOEM. However, if those negotiations do not result in an acceptable tailored plan and if we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition.

The consummation of the Exchange Offer may not occur on the expected timeline or at all.

The Exchange Offer is subject to the satisfaction of certain conditions, including that nothing has occurred or may occur that would or might, in our reasonable judgment, be expected to prohibit, prevent, restrict or delay the Exchange Offer. Even if the Exchange Offer is completed, it may not be completed on the schedule described in this Quarterly Report on Form 10-Q. Accordingly, eligible holders participating in the Exchange Offer may have to wait longer than expected to receive the consideration contemplated in the Exchange Offer, as the case may be, during which time those eligible holders will not be able to effect transfers of their Existing Notes tendered in the Exchange Offer.

If we incur substantially more debt, it could exacerbate the risks associated with our indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. As of June 30, 2016, we had $900.0 million of unsecured indebtedness under our Existing Notes and approximately $448.0 million of secured indebtedness outstanding, including $148.0 million under our revolving bank credit facility and $300.0 million of Existing Term Loans. After giving effect to the consummation of the Exchange Offer, the New Capital Financing, and the amendment of our revolving bank credit facility, we and the subsidiary guarantors would have had (assuming holders of 95% in principal amount of the outstanding Existing Notes participate in the Exchange Offer):

- $148.0 million of secured indebtedness under our revolving bank credit facility (not including $0.9 million in letters of credit outstanding secured by our revolving bank credit facility to which the New Second Lien Notes would be contractually junior (to the extent of the value of the collateral securing such indebtedness));

- $75.0 million in aggregate principal amount of the 1.5 Lien Term Loan, which will be junior only to the revolving bank credit facility and certain other customary permitted liens and will be secured by a 1.5 priority lien on all assets granted to secure indebtedness under our revolving bank credit facility (the proceeds of which we will use to repay amounts outstanding under our revolving bank credit facility and to pay fees and expenses associated therewith and for general corporate purposes);
- $300.0 million of 9.00% Term Loan;

- $192.4 million in aggregate principal amount of the New Second Lien Notes;
- $45.0 million in aggregate principal amount of Existing Notes; and
- $171.0 million in aggregate principal amount of the New Unsecured Notes.

The amounts above are principle amounts only and exclude adjustments to carrying amounts from the anticipated accounting for the Exchange Offer as a troubled debt restructuring under GAAP.

If new debt is added to our current debt levels, the related risks that we and our subsidiaries face could intensify. Our level of indebtedness may prevent us from engaging in certain transactions that might otherwise be beneficial to us by limiting our ability to obtain additional financing, limiting our flexibility in operating our business or otherwise. In addition, we could be at a competitive disadvantage against other less leveraged competitors that have more cash flow to devote to their business. Any of these factors could result in a material adverse effect on our business, financial condition, results of operations, business prospects and ability to satisfy our obligations under the New Notes.

Restrictions in our existing and future debt agreements could limit our growth and our ability to respond to changing conditions.

The indentures and credit agreements governing our indebtedness contain a number of significant restrictive covenants in addition to covenants restricting the incurrence of additional debt. These covenants limit our ability and the ability of our restricted subsidiaries, among other things, to:

- make loans and investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of our company;
- engage in transactions with our affiliates;
- pay dividends or make other distributions on capital stock or subordinated indebtedness; and
- create unrestricted subsidiaries.

Our revolving bank credit facility requires us, among other things, to maintain certain financial ratios and satisfy certain financial condition tests or reduce our debt. These restrictions may also limit our ability to obtain future financings, withstand a future downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indentures governing the New Second Lien Notes, the New Unsecured Notes and the Existing Notes, the term loan credit agreements governing the 1.5 Lien Term Loan and 9.00% Term Loan and our revolving bank credit facility impose on us.

A breach of any covenant in the agreements governing our debt would result in a default under such agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the debt outstanding under such agreement and in a default with respect to, and acceleration of, the debt outstanding under any other debt agreements. The accelerated debt would become immediately due and payable. If that should occur, we may not be able to make all of the required payments or borrow sufficient funds to refinance such accelerated debt. Even if new financing were then available, it may not be on terms that are acceptable to us.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index.

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 5, 2016.

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 INDEX

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 25, 2006)
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))
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.

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