W&T OFFSHORE INC
Form 10-Q
May 07, 2015

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 March 31, 2015

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 May 4, 2015, there were 75,936,731 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)

	March 31, 2015 (Unaudited)	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$8,367	$23,666
Receivables:		
Oil and natural gas sales	46,121	67,242
Joint interest and other	29,300	43,645
Total receivables	75,421	110,887
Deferred income taxes	3,196	11,662
Prepaid expenses and other assets	18,842	36,347
Total current assets	105,826	182,562
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which $110,704 at March 31, 2015 and $109,824 at December 31, 2014 were excluded from amortization)	8,133,244	8,045,666
Furniture, fixtures and other	23,495	23,269
Total property and equipment	8,156,739	8,068,935
Less accumulated depreciation, depletion and amortization	5,955,539	5,575,078
Net property and equipment	2,201,200	2,493,857
Restricted deposits for asset retirement obligations	15,501	15,444
Other assets	16,534	17,244
Total assets	$2,339,061	$2,709,107
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$128,277	$194,109
Undistributed oil and natural gas proceeds	29,171	37,009
Asset retirement obligations	16,500	36,003
Accrued liabilities	28,220	17,377
Total current liabilities	202,168	284,498
Long-term debt, less current maturities	1,426,437	1,360,057
Asset retirement obligations, less current portion	364,723	354,565
Deferred income taxes	74,875	186,988
Other liabilities	13,900	13,691
Commitments and contingencies	—	—

Shareholders' equity:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at March 31, 2015 and December 31, 2014	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 78,805,904 issued and 75,936,731 outstanding at March 31, 2015; 78,768,588 issued and 75,899,415 outstanding at December 31, 2014	1	1
Additional paid-in capital	417,325	414,580
Retained earnings (accumulated deficit)	(136,201)	118,894
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	256,958	509,308
Total liabilities and shareholders' equity	$2,339,061	$2,709,107

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 March 31,	
	2015	2014
	(In thousands except per share data) (Unaudited)	
Revenues	$127,907	$254,516
Operating costs and expenses:		
Lease operating expenses	53,331	55,617
Production taxes	637	1,992
Gathering and transportation	4,824	5,296
Depreciation, depletion, amortization and accretion	125,467	123,306
Ceiling test write-down of oil and natural gas properties	260,390	—
General and administrative expenses	20,766	23,588
Derivative loss	—	7,492
Total costs and expenses	465,415	217,291
Operating income (loss)	(337,508)	37,225
Interest expense:		
Incurred	22,944	21,460
Capitalized	(1,783)	(2,072)
Income (loss) before income tax expense (benefit)	(358,669)	17,837
Income tax expense (benefit)	(103,574)	6,648
Net income (loss)	$(255,095)	$11,189
Basic and diluted earnings (loss) per common share	$(3.36)	$0.15
Dividends declared per common share	$—	$0.10

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock Outstanding		Additional Paid-In Capital	Retained Earnings (Deficit)	Treasury Stock		Total Shareholders' Equity
	Shares	Value			Shares	Value	
	(In thousands)			(Unaudited)			
Balances at December 31, 2014	75,899	$ 1	$ 414,580	$ 118,894	2,869	$ (24,167)	$ 509,308
Share-based compensation	—	—	2,816	—	—	—	2,816
Other	38	—	(71)	—	—	—	(71)
Net loss	—	—	—	(255,095)	—	—	(255,095)
Balances at March 31, 2015	75,937	$ 1	$ 417,325	$ (136,201)	2,869	$ (24,167)	$ 256,958

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31,	
	2015	2014
	(In thousands) (Unaudited)	
Operating activities:		
Net income (loss)	$(255,095)	$11,189
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	125,467	123,306
Ceiling test write-down of oil and gas properties	260,390	—
Amortization of debt issuance costs and premium	156	187
Share-based compensation	2,816	3,758
Derivative loss	—	7,492
Cash payments on derivative settlements	—	(4,670)
Deferred income taxes	(103,574)	6,645
Changes in operating assets and liabilities:		
Oil and natural gas receivables	21,121	2,815
Joint interest and other receivables	14,533	2,286
Income taxes	(325)	(35)
Prepaid expenses and other assets	17,246	2,709
Asset retirement obligation settlements	(19,554)	(16,342)
Accounts payable, accrued liabilities and other	(62,439)	(20,850)
Net cash provided by operating activities	742	118,490
Investing activities:		
Investment in oil and natural gas properties and equipment	(82,765)	(95,067)
Purchases of furniture, fixtures and other	(226)	(260)
Net cash used in investing activities	(82,991)	(95,327)
Financing activities:		
Borrowings of long-term debt - revolving bank credit facility	82,000	92,000
Repayments of long-term debt - revolving bank credit facility	(15,000)	(103,000)
Dividends to shareholders	—	(7,563)
Other	(50)	(65)
Net cash provided by (used in) financing activities	66,950	(18,628)
Increase (decrease) in cash and cash equivalents	(15,299)	4,535
Cash and cash equivalents, beginning of period	23,666	15,800
Cash and cash equivalents, end of period	$8,367	$20,335

See Notes to Condensed Consolidated Financial Statements.

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

1. Basis of Presentation

Operations. W&T Offshore, Inc. and subsidiaries, referred to herein as "W&T," "we," "us," "our," or the "Company," is an independent oil and natural gas producer focused primarily in the Gulf of Mexico and onshore Texas. 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 our 100%-owned subsidiary, W & T Energy VI, LLC ("Energy VI").

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

Operating results for interim periods are not necessarily indicative of the results that may be expected for the entire year. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

Transactions between Entities under Common Control. The prior period financial information for the three months ended March 31, 2014 presented in Note 13, Supplemental Guarantor Information, has been retrospectively adjusted due to transactions between entities under common control, as required under authoritative guidance.

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.

Ceiling Test Write-Down. Under the full cost method of accounting, we are required to periodically 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 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, 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 to declines in the unweighted rolling average of first-day-of-the-month commodity prices in oil and natural gas prices, for the three months ended March 31, 2015, we recorded a ceiling test write-down which is reported as a separate line in the Statement of Operations. We did not have a ceiling test write-down for the three months ended March 31, 2014. Assuming oil and natural gas prices that we realized during the three months ended March 31, 2015 continue, we will likely have additional ceiling test write-downs during 2015. The magnitude of these write-downs cannot be estimated at this time.

Recent Events. The price we receive for our oil, natural gas liquids ("NGLs") and natural gas production directly affects our revenues, profitability, cash flows, liquidity, access to capital and future rate of growth. The prices of these commodities began falling beginning in the second half of 2014 and were significantly lower in the three months ended March 31, 2015 compared to the last few years.

We have taken several steps to mitigate the effects of these lower prices including: (i) significantly reducing the 2015 capital budget from the previous year; (ii) suspending our drilling and completion activities at several locations; (iii) suspending the regular quarterly common stock dividend and (iv) implementing numerous cost reduction projects to reduce our operating costs.

In April 2015, we entered into the First Amendment to the Fifth Amended and Restated Credit Agreement (the "Amendment"), which (i) set the borrowing base under our revolving credit facility at $600.0 million, (ii) provided that the borrowing base be reduced by $0.33 for every $1.00 of unsecured indebtedness, or debt which is subordinate in security compared to the lien securing borrowings under our revolving credit facility, in excess of the $900.0 million aggregate principal amount of existing notes, until such time as the borrowing base has been redetermined by the lenders, and (iii) amended certain existing covenants. See Note 12 for additional information regarding the Amendment.

In May 2015, we announced the pricing and marketing of a $300.0 million five-year second-lien term loan. The transaction did not close prior to the filing of this Form 10-Q and there is no assurance the term loan will be finalized and made. See Note 12 for additional information.

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 March 31, 2016; however, we cannot predict how an extended period of low commodity prices will affect our operations and liquidity levels.

Recent Accounting Developments. In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2015-03 ("ASU 2015-03"), Interest – Imputation of Interest (Subtopic 835-30), Simplifying the Presentation of Debt Issuance Costs. The guidance seeks to simplify the presentation of debt issuance costs. The amendment would require debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs would not be affected by the amendment. ASU 2015-03 is effective in 2016 and should be applied on a retrospective basis. Early adoption is permitted. We do not expect the revised guidance to materially affect our balance sheet as amounts will be reclassified from long-term assets to partial offsets to long-term debt. The revised guidance will not affect the statements of operations or the statements of cash flows.

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 May 2014, the FASB issued Accounting Standards Update No. 2014-09 ("ASU 2014-09"), Summary and Amendments that Create Revenue from Contracts and Customers (Topic 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.

2. Acquisitions and Divestitures

2014 Acquisitions

Fairway

On September 15, 2014, the Parent Company entered into an asset purchase agreement with a third party to increase its ownership interest from 64.3% to 100% in the Mobile Bay blocks 113 and 132 (the "Fairway Field") and the associated Yellowhammer gas processing plant (collectively, "Fairway"). The Fairway Field is located in the state waters of Alabama and the Yellowhammer gas processing plant is located in the state of Alabama. The effective date of the transaction was July 1, 2014. The transaction included customary adjustments for the effective date, certain closing adjustments and our assumption of the related asset retirement obligations ("ARO"). A net purchase price increase of $1.3 million for customary final closing adjustments was recorded in 2015. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

The following table presents the purchase price allocation, including adjustments, for the increased ownership interest in Fairway (in thousands):

Cash consideration:	
Evaluated properties including equipment	$18,693
Non-cash consideration:	
Asset retirement obligations - non-current	6,124
Total consideration	$24,817

The acquisition was recorded at fair value, which was determined by applying the market and income approaches using Level 3 inputs. The Level 3 inputs were: (i) analysis of comparable transactions obtained from various third-parties, (ii) estimates of ultimate recoveries of reserves and (iii) estimates of discounted cash flows based on estimated reserve quantities, reserve categories, timing of production, costs to produce and develop reserves, future prices, ARO and discount rates. The estimates and assumptions were determined by management and third-parties. The fair value is based on subjective estimates and assumptions, which are inherently imprecise, and the actual realized values could vary significantly from these estimates. No goodwill was recorded in connection with this acquisition of an additional working interest in Fairway.

Woodside Properties

On May 20, 2014, Energy VI entered into a purchase and sale agreement to acquire certain oil and natural gas property interests from Woodside Energy (USA) Inc. ("Woodside"). The properties acquired from Woodside (the "Woodside Properties") consisted of a 20% non-operated working interest in the producing Neptune field (deepwater Atwater Valley blocks 574, 575 and 618), along with an interest in the Neptune tension-leg platform, associated production facilities and various interests in 24 other deepwater lease blocks. All of the Woodside Properties are located in the Gulf of Mexico. The effective date of the transaction was November 1, 2013. The transaction included customary adjustments for the effective date, certain closing adjustments and our assumption of the related ARO. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

The following table presents the purchase price allocation, including adjustments, for the acquisition of the Woodside Properties (in thousands):

Cash consideration:	
Evaluated properties including equipment	$52,102
Unevaluated properties	2,660
Sub-total cash consideration	54,762
Non-cash consideration:	
Asset retirement obligations - current	782
Asset retirement obligations - non-current	10,543
Sub-total non-cash consideration	11,325
Total consideration	$66,087

The acquisition was recorded at fair value, which was determined by applying the market and income approaches using Level 3 inputs. The Level 3 inputs were: (i) analysis of comparable transactions obtained from various third-parties, (ii) estimates of ultimate recoveries of reserves and (iii) estimates of discounted cash flows based on estimated reserve quantities, reserve categories, timing of production, costs to produce and develop reserves, future prices, ARO and discount rates. The estimates and assumptions were determined by management and third-parties. The fair value is based on subjective estimates and assumptions, which are inherently imprecise, and the actual realized values could vary significantly from these estimates. No goodwill was recorded in connection with the Woodside Properties acquisition.

2014 Acquisitions — Revenues, Net Income and Pro Forma Financial Information

The increase in working interest ownership for Fairway was not included in our consolidated results until the property transfer date, which occurred in September 2014 and the incremental revenue and operating expenses were immaterial for the three month period ended March 31, 2015. Unaudited pro forma information is not presented as the pro forma information is not materially different from the reported results presented for the three months ended March 31, 2014.

The Woodside Properties were not included in our consolidated results until the property transfer date, which occurred in May 2014. For the three months ended March 31, 2015, the Woodside Properties accounted for $5.5 million of revenues, $3.2 million of direct operating expenses, $4.1 million of depreciation, depletion, amortization and accretion (“DD&A”) and $0.6 million of income tax benefit, resulting in $1.2 million of net loss. The net loss attributable to the Woodside Properties does not reflect certain expenses, such as general and administrative expenses (“G&A”) and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Woodside Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate.

In accordance with the applicable accounting guidance, the unaudited pro forma financial information was computed as if the acquisition of the Woodside Properties had been completed on January 1, 2013. The financial information was derived from W&T’s audited historical consolidated financial statements for annual periods, W&T’s unaudited historical condensed consolidated financial statements for interim periods, and the Woodside Properties’ unaudited historical financial statements for the annual and interim periods.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Woodside Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2013. Had we owned the Woodside Properties during the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than Woodside; the realized sales prices for oil, NGLs and natural gas may have been different; and the costs of operating the Woodside Properties may have been different.

The following table presents a summary of our pro forma financial information (in thousands, except earnings per share):

(unaudited)

	Three Months Ended March 31, 2014
Revenue	$ 268,375
Net income	14,976
Basic and diluted earnings per common share	0.20

For the pro forma financial information, certain information was derived from our financial records, Woodside's financial records and certain information was estimated.

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

The following table presents incremental items included in the pro forma information reported above for the Woodside Properties (in thousands):

	(unaudited) Three Months Ended March 31, 2014
Revenues (a)	$ 13,859
Direct operating expenses (a)	2,612
DD&A (b)	4,989
G&A (c)	200
Interest expense (d)	246
Capitalized interest (e)	(14)
Income tax expense (f)	2,039

The sources of information and significant assumptions are described below:

(a) Revenues and direct operating expenses for the Woodside Properties were derived from the historical financial records of Woodside.
(b) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Woodside Properties' costs, reserves and production into our full cost pool in order to compute such amounts. The purchase price allocated to unevaluated properties for oil and natural gas interests was excluded from the DD&A expense estimation. ARO was estimated by W&T management.
(c) Estimated insurance costs related to the Woodside Properties.
(d) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $54.8 million, which equates to the cash component of the acquisition purchase price, and an interest rate of 1.8%, which equates to the rates applied to incremental borrowings on the revolving bank credit facility.
(e) The change to capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings. The negative amount represents a decrease to net expenses.
(f) Income tax expense was computed using the 35% federal statutory rate.

The pro forma adjustments do not include adjustments related to any other acquisitions or divestitures.

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, 2014	$390,568
Liabilities settled	(19,554)
Accretion of discount	5,390
Liabilities incurred	1,536
Revisions of estimated liabilities [(1)]	3,283
Balance, March 31, 2015	381,223
Less current portion	16,500
Long-term	$364,723

(1) Revisions were primarily attributable to increases from non-operated properties.

4. Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and interest rates. As of March 31, 2015 and December 31, 2014, we did not have any open derivative contracts. During 2014, we used crude oil swap contracts and have used various derivative instruments in recent years to manage our exposure to commodity price risk from sales of our oil and natural gas. While these contracts were intended to reduce the effects of price volatility, they may have limited income from favorable price movements.

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 three months ended March 31, 2014. 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.

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

Three
Months

	Ended March 31, 2015	2014
Derivative loss	$—	$7,492

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

	Three Months Ended March 31, 2015	2014
Cash payments on derivative settlements, net	$—	$4,670

5. Long-Term Debt

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

	March 31, 2015	December 31, 2014
8.50% Senior Notes	$900,000	$900,000
Debt premiums, net of amortization	12,437	13,057
Revolving bank credit facility	514,000	447,000
Total long-term debt	1,426,437	1,360,057
Current maturities of long-term debt	—	—
Long term debt, less current maturities	$1,426,437	$1,360,057

At March 31, 2015 and December 31, 2014, the balance outstanding of our senior notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019 (the “8.50% Senior Notes”), was 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 March 31, 2015.

As of March 31, 2015, the Fifth Amended and Restated Credit Agreement (the “Original Credit Agreement”) governed our revolving bank credit facility and matures on November 8, 2018. Borrowings under our revolving bank credit facility are secured by our oil and natural gas properties. Availability under such 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.

At both March 31, 2015 and December 31, 2014, we had $0.6 million of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 3.2% for the three months ended March 31, 2015 for borrowings 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 March 31, 2015, our borrowing base was $750.0 million and our borrowing availability was $235.4 million.

In April 2015, we entered into the Amendment to the Original Credit Agreement (collectively, the “Credit Agreement”). The maturity date of the Original Credit Agreement was not changed by the Amendment and remains at November 8, 2018. The Amendment lowered the borrowing base to $600.0 million, revised the financial covenant tests and obligated us to certain additional restrictions and conditions. In addition, the Amendment modified certain financial ratio covenants retroactively to the reporting period for March 31, 2015. See Note 12 for information on the Amendment, the Credit Agreement and a pending term loan transaction.

Under the Credit Agreement, we are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio, a maximum leverage ratio, a maximum first lien leverage ratio, a maximum secured debt leverage ratio and a minimum interest coverage ratio. We were in compliance with all applicable covenants of the Credit Agreement as of March 31, 2015.

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

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 and published commodity futures prices. The fair value of our 8.50% Senior Notes is 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 8.50% Senior Notes and revolving bank credit facility, both of which are reported as liabilities (in thousands):

	Hierarchy	March 31, 2015	December 31, 2014
8.50% Senior Notes	Level 2	$555,750	$594,000
Revolving bank credit facility	Level 2	514,000	447,000

The 8.50% Senior Notes and revolving bank credit facility are reported in the balance sheet at their carrying value as described in Note 5.

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

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. As allowed by the Plan, during 2014 and in 2013, the Company granted restricted stock units (“RSUs”) to certain of its employees. During the three months ended March 31, 2015, 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 achievement 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 based on the Company and the employee achieving certain pre-defined performance criteria.

During 2014, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) net income before income tax expense, net interest expense, depreciation, depletion, amortization, accretion and certain other items (“Adjusted EBITDA”) for 2014 and (ii) Adjusted EBITDA as a percent of total revenue (“Adjusted EBITDA Margin”) for 2014. For 2014, the Company was above target for Adjusted EBITDA and was slightly below target for Adjusted EBITDA Margin.

During 2013, RSUs granted were also subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA for 2013; (ii) Adjusted EBITDA Margin for 2013; and (iii) the Company's total shareholder return ("TSR") ranking against peer companies' TSR for 2013, 2014 and January 1, 2015 to October 31, 2015. TSR is determined based upon the change in the entity's stock price plus dividends for the applicable performance period. For 2013, the Company exceeded the target for Adjusted EBITDA and was approximately at target for 2013 Adjusted EBITDA Margin. For 2014 and 2013, the Company was below target for the TSR rankings for each period.

All RSUs granted to date are subject to employment-based criteria and vesting occurs in December of the second year after the grant. For example, the RSUs granted during 2013 will vest in December 2015 to eligible employees assuming the requisite performance goals are also satisfied.

The 2014 annual incentive award for the Chief Executive Officer ("CEO") was settled in shares of common stock based on a pre-determined price of $14.66 per share, pursuant to the terms of his award. In March 2015, after reductions for employee payroll and withholding taxes, the net amount of the CEO's 2014 award resulted in 37,316 shares of common stock issued to the CEO. The 2013 annual incentive award for the CEO was settled in shares of common stock based at the price of $14.84, which was the Company's closing price the day prior to the settlement date. In March 2014, after reductions for employee payroll and withholding taxes, the net amount of the CEO's 2013 award resulted in 42,547 shares of common stock issued to the CEO. The CEO awards for both years were 100% performance based and were subject to pre-defined performance measures, which were the same pre-defined performance measures established for the other eligible Company employees, and were subject to approval of the Compensation Committee.

Under the Director Compensation Plan, shares of restricted stock ("Restricted Shares") have been granted to the Company's non-employee directors. No grants to non-employee directors were made during the three months ended March 31, 2015 but grants were made during 2014 and 2013. The Restricted Shares are subject to service conditions and vesting occurs at the end of specified service periods.

At March 31, 2015, there were 4,752,766 shares of common stock available for issuance in satisfaction of awards under the Plan and 500,564 shares of common stock available for issuance in satisfaction of awards under the Director Compensation Plan. The shares available for both plans are reduced when Restricted Shares or shares of common stock are granted. RSUs reduce the shares available in the Plan when the RSUs are settled in shares of common stock, net of withholding tax. Although the Company has the option to settle RSUs in stock or cash at vesting, only common stock has been used to settle vested RSUs to date.

We recognize compensation cost for share-based payments to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of grant. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that are expected to actually vest.

Awards Based on Restricted Stock to Non-Employee Directors. As of March 31, 2015, all of the unvested shares of Restricted Shares outstanding were issued to the non-employee directors. Restricted Shares are subject to forfeiture until vested and 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. The fair value of Restricted Shares was estimated by using the Company's closing price on the grant date.

Subject to the satisfaction of service conditions, the outstanding Restricted Shares issued to the non-employee directors as of March 31, 2015 are expected to vest as follows:

	Restricted Shares
2015	21,520
2016	15,420
2017	6,270

Total	43,210

There were no grants, forfeitures or vesting of Restricted Shares during the first quarter of 2015 or the first quarter of 2014.

Awards Based on Restricted Stock Units. As of March 31, 2015, the Company had outstanding RSUs issued to certain employees. As described above, the RSUs granted during 2014 and 2013 were 100% performance based and were subject to pre-defined performance measures. A portion of the RSUs granted during 2013 remains subject to the performance measure of TSR for the defined period in 2015; therefore, the number of RSUs may be adjusted upon determination of the performance. The RSUs subject to performance measurement which has not yet been determined are disclosed in the table below for RSUs potentially eligible to vest.

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(Unaudited)

The fair value for the RSUs granted during 2014 was determined using the Company's closing price on the grant date as the performance measures were all Company-specific performance measures comprised of Adjusted EBITDA and Adjusted EBITDA Margin. The fair value for the 2013 RSUs was determined separately for the components related to the TSR targets and the Company specific performance measures (Adjusted EBITDA and Adjusted EBITDA Margin). The fair value for the 2013 RSUs component related to TSR targets was determined by using a Monte Carlo simulation probabilistic model. The inputs used in the probabilistic model for the Company and the peer companies were: average closing stock prices during January 2013; risk-free interest rates using the London Interbank Offered Rate ("LIBOR") ranging from 0.27% to 0.91% over the service period; expected volatilities ranging from 30% to 63%; expected dividend yields ranging from 0.0% to 3.1%; and correlation factors ranging from a negative 84% to a positive 95%. The expected volatilities, expected dividends and correlation factors were developed using historical data. The fair value of all other 2013 RSUs components was determined using the Company's closing price on the grant date.

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 paid on our common stock after achieving the specified performance requirement for that component of the RSUs.

A summary of activity in 2015 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, December 31, 2014	1,977,335	$ 15.29
Forfeited	(49,541)	15.20
Nonvested, March 31, 2015	1,927,794	$ 15.29

All of the outstanding RSUs are subject to the satisfaction of service conditions and a portion of the outstanding RSUs are also subject to pre-defined performance measurements. The RSUs outstanding as of March 31, 2015 potentially eligible to vest are listed in the table below:

	Restricted Stock Units
2015 - subject to service requirements	739,620
2015 - subject to service and other requirements [1]	87,701
2016 - subject to service requirements	1,100,473

Total	1,927,794

(1) In addition to service requirements, these RSUs are also subject to TSR performance requirements not yet measureable, with awards ranging from 0% to 200% of amounts granted.

The grant date fair value of RSUs granted during the three months ended March 31, 2014 was $19.4 million. During the first quarter of 2015 and the first quarter of 2014, no RSUs vested.

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Share-Based Compensation. A summary of incentive compensation expense under share-based payment arrangements and the related tax benefit is as follows (in thousands):

	Three Months Ended March 31,	
	2015	2014
Share-based compensation expense from:		
Restricted stock	$93	$99
Restricted stock units	2,817	2,537
Common shares	(94)	1,122
Total	$2,816	$3,758
Share-based compensation tax benefit:		
Tax benefit computed at the statutory rate	$986	$1,315

Unrecognized Share-Based Compensation. As of March 31, 2015, unrecognized share-based compensation expense related to our awards of Restricted Shares and RSUs was $0.4 million and $13.7 million, respectively. Unrecognized share-based compensation expense will be recognized through April 2017 for Restricted Shares and November 2016 for RSUs.

Cash-Based Incentive Compensation. As defined by the Plan, annual incentive awards may be granted to eligible employees and payable in cash. (In the case of the award to the CEO, the awards for 2014 and 2013 were paid in shares of common stock as described above.) These awards are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each of such criteria. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year. As of March 31, 2015, the Company did not issue any cash-based incentive awards for 2015.

Share-Based Compensation and Cash-Based Incentive Compensation Expense. A summary of incentive compensation expense is as follows (in thousands):

	Three Months Ended March 31,	
	2015	2014
Share-based compensation included in:		
General and administrative	$2,816	$3,758
Cash-based incentive compensation included in:		

Lease operating expense	361	1,302
General and administrative [1]	(233)	1,781
Total charged to operating income	$2,944	$6,841

(1) Adjustments to true up estimates to actual payments resulted in net credit balances to expense for the three months ended March 31, 2015.

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8. Income Taxes

Income tax benefit was $103.6 million and income tax expense was $6.6 million for the three months ended March 31, 2015 and 2014, respectively. Our annualized effective tax rate of 28.9% for the three months ended March 31, 2015 differs from the federal statutory rate of 35% due to the effect of a valuation allowance for our deferred tax assets. Our effective tax rate for the three months ended March 31, 2014 was 37.3% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes and other permanent items.

During the quarter ended March 31, 2015, we recorded a valuation allowance of $22.5 million related to federal deferred tax assets and net operating losses. Additionally, as of March 31, 2015 and December 31, 2014, we had a valuation allowance related to Louisiana state net operating losses. 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. The tax years from 2010 through 2014 remain open to examination by the tax jurisdictions to which we are subject.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the three months ended March 31, 2015 and 2014, we recorded immaterial amounts of accrued interest expense related to our unrecognized tax benefit.

9. Earnings Per Share

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

	Three Months Ended March 31,	
	2015	2014
Net income (loss)	$(255,095)	$11,189
Less portion allocated to nonvested shares	—	120
Net income (loss) allocated to common shares	$(255,095)	$11,069
Weighted average common shares outstanding	75,857	75,556
Basic and diluted earnings (loss) per common share	$(3.36)	$0.15
Shares excluded due to being anti-dilutive (weighted-average)	201	—

10. Dividends

During the three months ended March 31, 2015, we did not declare or pay any dividends. During the three months ended March 31, 2014, we paid regular cash dividends per common share of $0.10. Pursuant to the Credit Agreement, the regular quarterly dividend is suspended until June 2016, and may be suspended further depending on certain financial covenants. See Note 12 for additional information.

11. Contingencies

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 relative to such underpayment. We believe the fine is excessive and extreme 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. 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 March 31, 2015 or December 31, 2014 per authoritative guidance. However, we cannot state with certainty that our estimate of the exposure is accurate concerning this matter.

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 unspecified actual damages, interest, court costs, and attorneys' fees. In February 2015, we made a payment to Apache for our net share of the amounts that we believe are reasonable to plug and abandon the three wells, all of which was originally recorded as an asset retirement obligation and was accrued on our balance sheet as of December 31, 2014. Our estimate of the potential exposure ranges from zero to $32 million related to this matter, which excludes potential interest, court costs and attorneys' fees.

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 $42 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 their portion of the settlement (approximately $5 million), in addition to a portion of interest owed. The other underwriters have not paid in accordance with the Fifth Circuit ruling, 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, Starr Marine has paid their portion ($5 million) of the first excess liability policy without interest. The lawsuit includes claims for interest underpaid by Liberty Mutual Insurance Co. and interest not paid by Starr Marine. The revised estimate of potential reimbursement is approximately $30 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 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 Board of Land Appeals (the "BLA") under the Department of the Interior. W&T's brief was filed in November 2014 and we expect the briefing before BLA to be completed in the first half of 2015.

Other Claims. We are a party to various pending or threatened claims and complaints seeking damages or other remedies concerning our commercial operations and other matters in the ordinary course of our business. In addition, claims or contingencies may arise related to matters occurring prior to our acquisition of properties or related to matters occurring subsequent to our sale of properties. In certain cases, we have indemnified the sellers of properties we have acquired, and in other cases, we have indemnified the buyers of properties we have sold. We are also subject to federal and state administrative proceedings conducted in the ordinary course of business. 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 three months ended March 31, 2015 and 2014. As of March 31, 2015 and December 31, 2014, we have recorded in liabilities no material amounts for claims, complaints and fines.

12. Subsequent Events

Amendment to the Credit Agreement. On April 23, 2015, the Company entered into the Amendment among the Company, as the borrower, Toronto Dominion (Texas) LLC, as the administrative agent, the lenders and other parties thereto. The Credit Agreement, as amended, provides a secured revolving bank credit facility that matures on November 8, 2018. The Amendment set the borrowing base as of the date of the Amendment at $600.0 million, subject to adjustments as described below.

The Amendment increased the applicable margin applied to borrowings under the Credit Agreement by 50 basis points (0.5%) on an annual basis such that the LIBOR borrowings are subject to applicable margins ranging from 2.25% to 3.25% and alternate base rate borrowings are subject to applicable margins ranging from 1.25% to 2.25%.

The Amendment permits the Company to issue additional unsecured indebtedness, or indebtedness which is subordinate in security compared to the lien securing the indebtedness under the Credit Agreement, above its current $900.0 million in aggregate principal amount of outstanding senior notes, provided that, among other things, (A) no event of default has occurred or would result from such incurrence, (B) the Company is in compliance with its current ratio, leverage ratio, secured debt leverage ratio and interest coverage ratio after giving pro forma effect to the incurrence of the additional indebtedness, and (C) such additional indebtedness matures at least six months after the maturity date of the Credit Agreement and is not subject to covenants and events of default that are, taken as a whole, materially more onerous than those provided for in the Credit Agreement.

Following the Amendment, if the Company issues additional unsecured indebtedness in excess of the $900.0 million in aggregate principal amount of existing senior notes or if the Company issues debt that is subordinated in security to the indebtedness secured under the Credit Agreement, the borrowing base then in effect will be reduced by $0.33 for each dollar of such excess until the borrowing base is redetermined. In addition, the borrowing base will be reduced to $550.0 million effective October 1, 2015 irrespective of whether any additional indebtedness is issued. The Amendment also restricts the ability of the Company to make distributions or repurchase the existing senior notes or other permitted indebtedness (i) until June 30, 2016, (ii) if an event of default is continuing or would result from such distribution or (iii) if a borrowing base deficiency is continuing or would result therefrom; provided that the restriction in clause (i) of this sentence does not apply to (A) scheduled payments of interest, principal or redemptions on the Company's existing senior notes or other permitted additional debt and (B) the redemption or repurchase by the Company of its outstanding senior notes in an aggregate principal amount equal to the aggregate principal amount of any new issuance of senior unsecured notes, provided that any such new notes are not subject to covenants and events of default that are, taken as a whole, materially more restrictive on the Company than its outstanding senior notes and such new notes mature at least six months after the maturity date of the Credit Agreement.

The Amendment revised the financial covenants, with definitions of capitalized terms contained in the Credit Agreement, as follows:

- the maximum Leverage Ratio is suspended through the first quarter of 2016; then limited to 5.00:1.00 for the second quarter of 2016; 4.50:1.00 for the third quarter of 2016; and 4.00:1.00 thereafter;
- the minimum Current Ratio is 0.75:1.00 for the first quarter of 2015 through the fourth quarter of 2015; and 1.00:1.00 thereafter;
- a maximum First Lien Leverage Ratio of 2.50:1.00 is effective for the first quarter of 2015 and thereafter;
- a maximum Secured Debt Leverage Ratio of 3.50:1.00 is effective for the first quarter of 2015 and thereafter; and
- a minimum Interest Coverage Ratio of 2.20:1.00 is effective for the first quarter of 2015 and thereafter.

The Amendment increases the mortgaged collateral requirement from 80% to 90% of the total value of both the (i) total proved oil and gas reserves of the loan parties and (ii) the proved developed producing reserves of the loan parties. The Amendment requires the Company to establish and maintain minimum hedge positions by June 1, 2015 of 25% of estimated oil and gas production for the period of June 1 to December 31, 2015 and 35% of estimated oil and gas production for 2016.

The foregoing description of the Credit Agreement does not purport to be complete and is qualified in its entirety by reference to the Amendment and the Original Credit Agreement.

Second Lien Term Loan. On May 5, 2015, we announced the pricing and marketing of a $300.0 million five-year second-lien term loan. The term loan is expected to be made subject to a 1.0% discount to principal bearing interest at an annual rate of 9.0%. It is expected that the CEO, or an entity controlled by the CEO, will participate in the term loan for a $5.0 million principal commitment on the same terms as the other lenders. Net borrowings under the term loan will be used to repay a portion of the outstanding borrowings under the revolver bank credit facility. Upon issuance of the term loan, the borrowing base of the revolving bank credit facility will be reduced from $600.0 million to $500.0 million pursuant to the terms of the Credit Agreement, as amended.

The lender commitments and making of the term loan are subject to the negotiation, approval and execution of definitive loan documentation, which includes an intercreditor agreement to be approved by the lenders under the Credit Agreement, as amended. The transaction did not close prior to the filing of this Form 10-Q. While the transaction is expected to close during May 2015, there is no assurance the term loan will be finalized and made.

13. Supplemental Guarantor Information

Our payment obligations under the 8.50% Senior Notes and the Credit Agreement (see Note 5 and Note 12) are fully and unconditionally guaranteed by certain of our 100%-owned subsidiaries, including W & T Energy VI, LLC 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 (as such term is defined in the indenture governing the 8.50% Senior Notes of the Company, if the sale or other disposition does not violate the “Asset Sales” provisions of the indenture;

(2) in connection with any sale or other disposition of the capital stock of such Guarantor Subsidiary to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the “Asset 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 the indenture;

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

(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 the indenture, 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, including related ARO and deferred income tax liabilities, were made during 2014 from the Parent Company to the Guarantor Subsidiaries to assist the Parent Company to continue to qualify for a waiver of certain supplemental bonding requirements from the Bureau of Ocean Energy Management. 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. The condensed consolidating financial information for the prior period ended March 31, 2014 was adjusted as if all transfers occurred at the beginning of the period presented. None of the above 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 March 31, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$ 8,367	$ —	$ —	$ 8,367
Receivables:				
Oil and natural gas sales	27,184	18,937	—	46,121
Joint interest and other	115,017	—	(85,717)	29,300
Total receivables	142,201	18,937	(85,717)	75,421
Deferred income taxes	34,656	1,865	(33,325)	3,196
Prepaid expenses and other assets	14,400	4,442	—	18,842
Total current assets	199,624	25,244	(119,042)	105,826
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,058,159	2,075,085	—	8,133,244
Furniture, fixtures and other	23,495	—	—	23,495
Total property and equipment	6,081,654	2,075,085	—	8,156,739
Less accumulated depreciation, depletion and amortization	4,705,609	1,249,930	—	5,955,539
Net property and equipment	1,376,045	825,155	—	2,201,200
Restricted deposits for asset retirement obligations	15,501	—	—	15,501
Other assets	911,505	316,253	(1,211,224)	16,534
Total assets	$ 2,502,675	$ 1,166,652	$ (1,330,266)	$ 2,339,061
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 122,627	$ 5,650	$ —	$ 128,277
Undistributed oil and natural gas proceeds	28,152	1,019	—	29,171
Asset retirement obligations	10,153	6,347	—	16,500
Accrued liabilities	28,592	85,345	(85,717)	28,220
Total current liabilities	189,524	98,361	(85,717)	202,168
Long-term debt, less current maturities	1,426,437	—	—	1,426,437
Asset retirement obligations, less current portion	240,943	123,780	—	364,723
Deferred income taxes	382	107,818	(33,325)	74,875
Other liabilities	388,431	—	(374,531)	13,900
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	417,325	703,237	(703,237)	417,325
Retained earnings (accumulated deficit)	(136,201)	133,456	(133,456)	(136,201)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	256,958	836,693	(836,693)	256,958

Total liabilities and shareholders’ equity	$2,502,675	$1,166,652	$(1,330,266)	$2,339,061

Condensed Consolidating Balance Sheet as of December 31, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$23,666	$—	$—	$ 23,666
Receivables:				
Oil and natural gas sales	41,820	25,422	—	67,242
Joint interest and other	142,885	—	(99,240)	43,645
Total receivables	184,705	25,422	(99,240)	110,887
Deferred income taxes	9,797	1,865	—	11,662
Prepaid expenses and other assets	28,728	7,619	—	36,347
Total current assets	246,896	34,906	(99,240)	182,562
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,038,915	2,006,751	—	8,045,666
Furniture, fixtures and other	23,269	—	—	23,269
Total property and equipment	6,062,184	2,006,751	—	8,068,935
Less accumulated depreciation, depletion and amortization	4,442,899	1,132,179	—	5,575,078
Net property and equipment	1,619,285	874,572	—	2,493,857
Restricted deposits for asset retirement obligations	15,444	—	—	15,444
Other assets	974,049	349,912	(1,306,717)	17,244
Total assets	$2,855,674	$1,259,390	$(1,405,957)	$ 2,709,107
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$188,654	$5,455	$—	$ 194,109
Undistributed oil and natural gas proceeds	36,130	879	—	37,009
Asset retirement obligations	30,711	5,292	—	36,003
Accrued liabilities	17,437	99,180	(99,240)	17,377
Total current liabilities	272,932	110,806	(99,240)	284,498
Long-term debt, less current maturities	1,360,057	—	—	1,360,057
Asset retirement obligations, less current portion	235,876	118,689	—	354,565
Deferred income taxes	59,616	127,372	—	186,988
Other liabilities	417,885	—	(404,194)	13,691
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	414,580	703,440	(703,440)	414,580
Retained earnings	118,894	199,083	(199,083)	118,894
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	509,308	902,523	(902,523)	509,308
Total liabilities and shareholders' equity	$2,855,674	$1,259,390	$(1,405,957)	$ 2,709,107

Condensed Consolidating Statement of Operations for the Three Months Ended March 31, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$82,463	$45,444	$ -	$ 127,907
Operating costs and expenses:				
Lease operating expenses	37,386	15,945	—	53,331
Production taxes	637	—	—	637
Gathering and transportation	2,548	2,276	—	4,824
Depreciation, depletion, amortization and accretion	75,152	50,315	—	125,467
Ceiling test write-down of oil and natural gas properties	190,695	69,695	—	260,390
General and administrative expenses	12,388	8,378	—	20,766
Total costs and expenses	318,806	146,609	—	465,415
Operating loss	(236,343)	(101,165)	—	(337,508)
Loss of affiliates	(65,627)	—	65,627	—
Interest expense:				
Incurred	22,230	714	—	22,944
Capitalized	(1,069)	(714)	—	(1,783)
Loss before income tax benefit	(323,131)	(101,165)	65,627	(358,669)
Income tax benefit	(68,036)	(35,538)	—	(103,574)
Net loss	$(255,095)	$(65,627)	$ 65,627	$ (255,095)

Condensed Consolidating Statement of Operations for the Three Months Ended March 31, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$143,986	$ 110,530	$ —	$ 254,516
Operating costs and expenses:				
Lease operating expenses	39,110	16,507	—	55,617
Production taxes	1,992	—	—	1,992
Gathering and transportation	3,338	1,958	—	5,296
Depreciation, depletion, amortization and accretion	62,431	60,875	—	123,306
General and administrative expenses	11,445	12,143	—	23,588
Derivative loss	7,492	—	—	7,492
Total costs and expenses	125,808	91,483	—	217,291
Operating income	18,178	19,047	—	37,225

Earnings of affiliates	12,451	—	(12,451)	—
Interest expense:				
Incurred	20,679	781	—	21,460
Capitalized	(1,291)	(781)	—	(2,072)
Income before income tax expense	11,241	19,047	(12,451)	17,837
Income tax expense	52	6,596	—	6,648
Net income	$11,189	$ 12,451	$ (12,451)	$ 11,189

Condensed Consolidating Statement of Cash Flows for the Three Months Ended March 31, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net loss	$ (255,095)	$ (65,627)	$ 65,627	$ (255,095)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	75,152	50,315	—	125,467
Ceiling test write-down of oil and gas properties	190,695	69,695	—	260,390
Amortization of debt issuance costs and premium	156	—	—	156
Share-based compensation	2,816	—	—	2,816
Deferred income taxes	(83,649)	(19,925)	—	(103,574)
Loss of affiliates	65,627	—	(65,627)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	14,636	6,485	—	21,121
Joint interest and other receivables	14,533	—	—	14,533
Income taxes	15,287	(15,612)	—	(325)
Prepaid expenses and other assets	7,924	38,985	(29,663)	17,246
Asset retirement obligation settlements	(19,122)	(432)	—	(19,554)
Accounts payable, accrued liabilities and other	(92,436)	334	29,663	(62,439)
Net cash provided by (used in) operating activities	(63,476)	64,218	—	742
Investing activities:				
Investment in oil and natural gas properties and equipment	(18,750)	(64,015)	—	(82,765)
Investment in subsidiary	203	—	(203)	—
Purchases of furniture, fixtures and other	(226)	—	—	(226)
Net cash used in investing activities	(18,773)	(64,015)	(203)	(82,991)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	82,000	—	—	82,000
Repayments of long-term debt – revolving bank credit facility	(15,000)	—	—	(15,000)
Other	(50)	—	—	(50)
Investment from parent	—	(203)	203	—
Net cash provided by financing activities	66,950	(203)	203	66,950
Decrease in cash and cash equivalents	(15,299)	—	—	(15,299)
Cash and cash equivalents, beginning of period	23,666	—	—	23,666
Cash and cash equivalents, end of period	$ 8,367	$ —	$ —	$ 8,367

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Condensed Consolidating Statement of Cash Flows for the Three Months Ended March 31, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$11,189	$ 12,451	$ (12,451)	$ 11,189
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	62,431	60,875	—	123,306
Amortization of debt issuance costs and premium	187	—	—	187
Share-based compensation	3,758	—	—	3,758
Derivative loss	7,492	—	—	7,492
Cash payments on derivative settlements	(4,670)	—	—	(4,670)
Deferred income taxes	15,335	(8,690)	—	6,645
Earnings of affiliates	(12,451)	—	12,451	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	4,020	(1,205)	—	2,815
Joint interest and other receivables	2,286	—	—	2,286
Income taxes	(15,321)	15,286	—	(35)
Prepaid expenses and other assets	(34,910)	(53,598)	91,217	2,709
Asset retirement obligations	(8,878)	(7,464)	—	(16,342)
Accounts payable, accrued liabilities and other	69,230	1,137	(91,217)	(20,850)
Net cash provided by operating activities	99,698	18,792	—	118,490
Investing activities:				
Investment in oil and natural gas properties and equipment	(71,636)	(23,431)	—	(95,067)
Investment in subsidiary	(4,639)	—	4,639	—
Proceeds from sales of assets and other, net	-	—	—	-
Purchases of furniture, fixtures and other	(260)	—	—	(260)
Net cash used in investing activities	(76,535)	(23,431)	4,639	(95,327)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	92,000	—	—	92,000
Repayments of long-term debt – revolving bank credit facility	(103,000)	—	—	(103,000)
Dividends to shareholders	(7,563)	—	—	(7,563)
Investment from parent	—	4,639	(4,639)	—
Other	(65)	—	—	(65)
Net cash used in financing activities	(18,628)	4,639	(4,639)	(18,628)
Increase in cash and cash equivalents	4,535	—	—	4,535
Cash and cash equivalents, beginning of period	15,800	—	—	15,800
Cash and cash equivalents, end of period	$20,335	$ —	$ —	$ 20,335

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, 2014 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 and onshore in the Permian Basin of West Texas. We have grown through acquisitions, exploration and development and currently hold working interests in 63 producing offshore fields in federal and state waters (61 producing and two fields capable of producing). We have interests in offshore leases covering approximately 1.1 million gross acres (0.7 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. On a gross acreage basis, the conventional shelf constitutes approximately 52% and deepwater constitutes approximately 48% of our offshore acreage. Onshore, we have leasehold interests in approximately 50,000 gross acres (40,000 net acres), substantially all of which are in Texas. A substantial majority of our daily production is derived from wells we operate offshore. Our interest in fields, leases, structures and equipment are primarily owned by the parent company, W&T Offshore, Inc. and our wholly-own subsidiary, W & T Energy VI, LLC. In managing our business, we are concerned primarily with maximizing return on shareholders' equity. To accomplish this primary goal, we focus on increasing production and reserves at a profit. We strive to grow our reserves and production through acquisitions and our drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to continue to add reserves post-acquisition.

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 quarter of 2015 were comprised of 43.1% oil and condensate, 10.1% NGLs and 46.8% 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 quarter of 2015, revenues from the sale of oil and NGLs made up 69.6% of our total revenues compared to 74.9% for the same period of 2014. For the first quarter of 2015, our combined total production was 0.8% higher than the first quarter of

2014 due to higher oil production, partially offset by lower production for NGLs and natural gas. For the first quarter of 2015, our total revenues were 49.7% lower than the first quarter of 2014 due to significantly lower realized prices for oil, NGLs and natural gas. See Results of Operations – Three Months Ended March 31, 2015 Compared to the Three Months Ended March 31, 2014 for additional information on our revenues and production.

In September 2014, we acquired an additional ownership interest in the Fairway Field and associated Yellowhammer gas processing plant, which increased our ownership interest from 64.3% to 100%. The Fairway Field (Mobile Bay blocks 113 and 132) is located in the state waters of Alabama and the Yellowhammer gas processing plant is located in the state of Alabama. Operating results for the increased ownership interest in Fairway are included in our results since the closing date of September 15, 2014. The results for the first quarter of 2014 do not include the increased ownership interest in Fairway as this period precedes the acquisition date. See Financial Statements - Note 2 - Acquisitions and Divestitures under Part I, Item 1 of this Form 10-Q for additional information.

In May 2014, we acquired certain oil and natural gas property interests in the Gulf of Mexico from Woodside. The Woodside Properties consisted of a 20% non-operated working interest in the producing Neptune field (deepwater Atwater Valley blocks 574, 575 and 618), along with an interest in the Neptune tension-leg platform, associated production facilities and various interests in 24 other deepwater blocks. Operating results for the Woodside Properties are included in our results since the closing date of May 20, 2014. The results for the first quarter of March 31, 2014 do not include the Woodside Properties' operations as this period precedes the acquisition date. See Financial Statements - Note 2 - Acquisitions and Divestitures under Part I, Item 1 of this Form 10-Q for additional information.

Our operating results are strongly influenced by the price of the commodities that we produce and sell. The price of those commodities is affected by both domestic and international factors, including domestic production. Beginning in the second half of 2014 and continuing through the first quarter of 2015, crude oil prices have fallen dramatically from a peak of over $100 per barrel for West Texas Intermediate ("WTI") in June 2014. In addition, prices of NGLs and natural gas have fallen significantly from 2014 levels. The current market imbalance is predominantly supply driven caused by a number of issues that are described below:

The U.S. Energy Information Administration ("EIA") estimates the worldwide crude oil and petroleum liquids supply will exceed demand in 2015, resulting in crude oil and other petroleum liquids inventories increasing by 1.7 million barrels per day in the first half of 2015 and by 1.1 million barrels per day for the full year of 2015. This is on top of inventory builds of 1.0 million barrels per day in 2014. EIA projects small inventory builds for 2016, primarily due to decreases in U.S. production. The combined inventories of the countries within the Organization for Economic Cooperation and Development (as defined by the EIA) were the highest on record and were equivalent to 59 days of consumption. These inventory builds are expected to keep downward pressure on prices. For the first quarter of 2015 compared to the first quarter of 2014, worldwide supply increased 2.0 million barrels per day, with the U.S. having the largest increase of 1.5 million barrels per day and OPEC's combined net supply increasing by 0.5 million barrels per day. Consumption for the first quarter of 2015 increased by 1.1 million barrels per day over the first quarter of 2014 and no single country or group caused the majority of the increase. According to analysts, Saudi Arabia increased production in March 2015 from February 2015 by 0.7 million barrels per day, which eclipsed its prior peak in August 2013. Including the Saudi Arabia increase, OPEC increased production in March 2015 from February by 0.8 million barrels per day. Many countries, such as Russia, Iraq, Iran, Venezuela, have economies that are highly (or solely) dependent on oil revenues and do not have significant cash reserves like Saudi Arabia; therefore, production reductions from these countries is not expected. If agreements are reached with Iran that leads to lifting oil-related sanctions, this could further exacerbate the excess crude oil supply situation. The lifting of oil-related sanctions for Iran has not been incorporated into EIA's projections. Conversely, if there is a major conflict in an oil producing country, this could cause supply disruptions.

While many U. S. producers have reduced capital budgets for 2015 compared to 2014 and operating drilling rigs have fallen dramatically (discussed below), EIA projects U.S. petroleum and other liquids production to increase in 2015 over 2014 by 0.8 million barrels per day. In addition, the increasing strength in the U.S. dollar relative to other currencies has also had 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 quarter of 2015, our average realized oil sales price was $43.04, down from $98.56 per barrel (56.3% lower) for the first quarter of 2014. The two primary benchmarks reported upon are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $48.49 per barrel for the first quarter of 2015, down from $98.68 per barrel (50.9% lower) for the first quarter of 2014. Brent crude oil prices decreased to $53.98 per barrel for the first quarter of 2015, down from $108.14 per barrel (50.1% lower) for the first quarter of 2014. Our average realized oil sales price percentage decrease for the first quarter of 2015 differs from the benchmarks primarily due to the realized prices received for our offshore crude oil production. Over 85% of our oil is 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. The premiums for our offshore crude oil have declined and sometimes are priced at a discount to WTI. For example, the monthly average premiums to WTI for LLS, HLS and Poseidon for the first quarter of 2015 were $2.60, $1.42 and a negative $2.14 per barrel, respectively, compared to $6.06, $6.90 and $1.18 per barrel, respectively, for the first quarter of 2014. In addition, Permian Basin realized crude oil prices may differ from the WTI benchmark due to infrastructure capacity and transportation costs incurred by the purchaser, with larger discounts applied where the oil is trucked due to lack of pipeline access.

Despite the significant uncertainty, EIA projects crude oil prices for WTI and Brent to be relatively flat for the second quarter of 2015 compared to the first quarter of 2015 and increase in the second half of 2015. EIA estimates 2015 crude oil prices per barrel for WTI and Brent to be $52.48 and $59.32, respectively, and to increase in 2016 to $70.00 and $75.03 per barrel, respectively. Factors identified by EIA that could cause crude oil prices to deviate significantly from their projections is the lifting of oil-related sanctions for Iran and unplanned outages from a wide range of producers.

During the first quarter of 2015, our average realized NGLs sales price decreased 56.1% compared to the first quarter of 2014. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the first quarter of 2015, average prices for domestic ethane decreased 49% and average domestic propane prices decreased 59% from the first quarter of 2014. Average price decreases for other domestic NGLs were approximately 50%. The price changes were reflective of the price changes for crude oil and natural gas. As long as U.S. crude oil and natural gas production remain high and 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 and would, in turn, suggest continued downward price pressure, especially on the price of ethane. 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.

During the first quarter of 2015, our average realized natural gas sales price decreased 40.0% compared to the first quarter of 2014. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 44.0% lower in the first quarter from the first quarter of 2014. 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. The U.S. natural gas inventories at the end of March 2015, which is designated as the end of the heating season, were 75% higher than a year earlier but were 12% lower than the previous five-year average. Storage withdrawals in the first quarter of 2015 were lower than the previous year primarily due to increased production. U.S. consumption increased in the first quarter of 2015 compared to the previous year, but was significantly less than the production increase. Consumption increases came from higher electric power and industrial usage, while residential and commercial usage was lower.

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

EIA projects natural gas prices to be relatively flat for the second quarter of 2015 compared to the first quarter of 2015 and increase in the second half of 2015. EIA estimates natural gas prices (Henry Hub spot price) for the full year 2015 and 2016 at $3.16 and $3.55 per Mcf, respectively. As a reference point, the Henry Hub spot price was $4.52 per Mcf for 2014. U.S. production is projected to be higher in 2015 and 2016 compared to 2014 by 4%, putting downward pressure on prices. Natural gas usage for power generation is expected to increase to 30% in 2015 and 2016 from 27% in 2014 due to lower natural gas prices compared to coal and new Federal regulations related to coal usage.

During the first quarter of 2015, the rig counts for oil and natural gas in the U.S. have declined significantly from 2014 levels due to lower crude oil and natural gas prices. According to Baker Hughes, the oil rig count at the beginning of 2014 was 1,378 and increased to 1,482 at the end of 2014. As of the end of March 2015, the oil rig count was 802, a decrease of 46% from year end 2014. The U.S. natural gas rig count was 372 at the beginning of 2014 and decreased to 328 at the end of 2014. As of the end of March 2015, the natural gas rig count was 222, a decrease of 32% from year end 2014. In the Gulf of Mexico, there were 59 rigs (39 oil and 20 natural gas) at the beginning of 2014 and 54 rigs (42 oil and 12 natural gas) at the end of 2014. As of the end of March 2015, there were 29 rigs (22 oil and 7 natural gas) in the Gulf of Mexico, a decrease of 46% from year end 2014.

As required by the full cost accounting rules, we performed our ceiling test calculation as of March 31, 2015 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 was $79.21 per barrel for crude oil and $3.88 per Mcf for natural gas. (For reference, the average prices for the first quarter of 2015 were $48.49 per barrel for WTI crude oil and $2.99 per Mcf for natural gas using Henry Hub spot prices.) Due to the decrease in the 12-month average price for both crude oil and natural gas, we recorded a ceiling test write-down of the carrying value of our oil and natural gas properties for the first quarter of 2015 of $260.4 million. We are required to perform the ceiling test calculation at the end of each quarter. If WTI and Brent prices remain at levels occurring during the first quarter of 2015, we estimate that we will likely recognize further non-cash ceiling test write-downs during 2015.

In April 2015, we entered into the Amendment to our Original Credit Agreement, which (i) set the borrowing base under our revolving credit facility at $600.0 million, (ii) provided that the borrowing base be reduced by $0.33 for every $1.00 of unsecured indebtedness, or debt which is subordinate in security compared to the lien securing borrowings under our revolving credit facility, in excess of the $900.0 million aggregate principal amount of existing notes, until such time as the borrowing base has been redetermined by the lenders, and (iii) amended certain existing covenants. The Original Credit Agreement, the Amendment and the Credit Agreement are more fully described in Financial Statements – Note 5 – Long-Term Debt and Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q.

On May 5, 2015, we announced the pricing and marketing of a $300.0 million five-year second-lien term loan, but the transaction had not closed prior to the filing of this Form 10-Q and there is no assurance that the term loan will be finalized and closed. The term loan is described in Financial Statements – Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q.

Weak commodity prices in the first quarter of 2015 have had a significant impact on our business, as discussed in the section titled Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014 under this Item. For a discussion of the potential impact of weak commodity prices in the future, see the section titled Liquidity and Capital Resources under this Item.

Many changes in laws, regulations, guidance, interpretations and policy continue to be proposed and issued in our industry. The most significant regulation change being proposed recently involves allowable deductions in the calculation of royalty payments to the U.S. government. The proposals would eliminate certain deductions, which would increase our royalty payments and decrease our revenue, earnings and liquidity. At this time, we are unable to assess the potential impact as clarification is needed for items within the proposals.

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 March 31,			
	2015[1]	2014	Change	%
	(In thousands, except percentages and per share data)			
Financial:				
Revenues:				
Oil	$81,527	$170,705	$(89,178)	(52.2)%
NGLs	7,446	20,022	(12,576)	(62.8)%
Natural gas	37,175	63,338	(26,163)	(41.3)%
Other	1,759	451	1,308	NM
Total revenues	127,907	254,516	(126,609)	(49.7)%
Operating costs and expenses:				
Lease operating expenses	53,331	55,617	(2,286)	(4.1)%
Production taxes	637	1,992	(1,355)	(68.0)%
Gathering and transportation	4,824	5,296	(472)	(8.9)%
Depreciation, depletion, amortization and accretion	125,467	123,306	2,161	1.8%
Ceiling test write-down of oil and natural gas properties	260,390	—	260,390	NM
General and administrative expenses	20,766	23,588	(2,822)	(12.0)%
Derivative loss	—	7,492	(7,492)	NM
Total costs and expenses	465,415	217,291	248,124	114.2%
Operating income (loss)	(337,508)	37,225	(374,733)	NM
Interest expense, net of amounts capitalized	21,161	19,388	1,773	9.1%

Income (loss) before income tax expense (benefit)	(358,669)	17,837	(376,506)	NM
Income tax expense (benefit)	(103,574)	6,648	(110,222)	NM
Net income (loss)	$(255,095)	$11,189	$(266,284)	NM
Basic and diluted earnings (loss) per common share	$(3.36)	$0.15	$(3.51)	NM

(1) In the second quarter of 2014, we acquired the Woodside Properties and, in the third quarter of 2014, we acquired the remaining working interest in Fairway that we did not already own.

	Three Months Ended March 31, 2015[1]	2014	Change	% [2]
Operating: [3]				
Net sales:				
Oil (MBbls)	1,894	1,732	162	9.4 %
NGLs (MBbls)	443	523	(80)	(15.3)%
Natural gas (MMcf)	12,349	12,618	(269)	(2.1)%
Total oil equivalent (MBoe)	4,395	4,358	37	0.8 %
Total natural gas equivalents (MMcfe)	26,372	26,150	222	0.8 %
Average daily equivalent sales (Boe/day)	48,837	48,427	410	0.8 %
Average daily equivalent sales (Mcfe/day)	293,022	290,560	2,462	0.8 %
Average realized sales prices:				
Oil ($/Bbl)	$43.04	$98.56	$(55.52)	(56.3)%
NGLs ($/Bbl)	16.81	38.26	(21.45)	(56.1)%
Natural gas ($/Mcf)	3.01	5.02	(2.01)	(40.0)%
Oil equivalent ($/Boe)	28.70	58.29	(29.59)	(50.8)%
Natural gas equivalent ($/Mcfe)	4.78	9.72	(4.94)	(50.8)%
Average per Boe ($/Boe):				
Lease operating expenses	$12.13	$12.76	$(0.63)	(4.9)%
Gathering and transportation	1.10	1.22	(0.12)	(9.8)%
Production costs	13.23	13.98	(0.75)	(5.4)%
Production taxes	0.14	0.46	(0.32)	(69.6)%
DD&A	28.55	28.29	0.26	0.9 %
General and administrative expenses	4.72	5.41	(0.69)	(12.8)%
	$46.64	$48.14	$(1.50)	(3.1)%
Average per Mcfe ($/Mcfe):				
Lease operating expenses	$2.02	$2.13	$(0.11)	(5.2)%
Gathering and transportation	0.19	0.20	(0.01)	(5.0)%
Production costs	2.21	2.33	(0.12)	(5.2)%
Production taxes	0.02	0.08	(0.06)	(75.0)%
DD&A	4.76	4.72	0.04	0.8 %
General and administrative expenses	0.79	0.90	(0.11)	(12.2)%
	$7.78	$8.03	$(0.25)	(3.1)%

(1) In the second quarter of 2014, we acquired the Woodside Properties and, in the third quarter of 2014, we acquired the remaining working interest in Fairway that we did not already own.

(2)

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

(3) 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.

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

	Three Months Ended March 31, 2015	2014	Change	%
Wells drilled (gross):				
Offshore	2	2	—	—
Onshore	4	10	(6)	(60.0)%
Productive wells drilled (gross)				
Offshore	2	2	—	—
Onshore	4	10	(6)	(60.0)%

Three Months Ended March 31, 2015 Compared to the Three Months Ended March 31, 2014

Revenues. Total revenues decreased $126.6 million, or 49.7%, to $127.9 million for the first quarter of 2015 as compared to the first quarter of 2014. Oil revenues decreased $89.2 million, or 52.2%, NGLs revenues decreased $12.6 million, or 62.8%, natural gas revenues decreased $26.2 million, or 41.3%, and other revenues increased $1.4 million. The oil revenue decrease was attributable to a 56.3% decrease in the average realized sales price to $43.04 per barrel for the first quarter of 2015 from $98.56 per barrel for the first quarter of 2014, partially offset by a 9.4% increase in sales volumes. The NGLs revenue decrease was attributable to a 56.1% decrease in the average realized sales price to $16.81 per barrel for the first quarter of 2015 from $38.26 per barrel for the first quarter of 2014 and a decrease of 15.3% in sales volumes. The decrease in natural gas revenue resulted from a 40.0% decrease in the average realized natural gas sales price to $3.01 per Mcf for the first quarter of 2015 from $5.02 per Mcf for the first quarter of 2014 and from a decrease of 2.1% in sales volumes. We experienced increases in production from acquisitions at the Neptune field and the Fairway field, and from Mississippi Canyon 506 (Wrigley), which had deferred production in the first quarter of 2014 as a result of maintenance at the host platform. Production was negatively impacted for all commodities from natural production declines and production deferrals affecting various fields. Production deferrals were attributable to third-party pipeline outages, operational issues, and maintenance. We estimate production deferrals were 0.5 million barrels of oil equivalent ("MMBoe") during the first quarter of 2015 which occurred at multiple locations. During the first quarter of 2014, we experienced production deferrals of 0.7 MMBoe.

Revenues from oil and liquids as a percent of our total revenues were 69.6% for the first quarter of 2015 compared to 74.9% for the first quarter of 2014 period. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 39.1% for the first quarter of 2015 compared to 38.8% for the first quarter of 2014 period.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workover and maintenance expenses on our facilities, as well as hurricane related expenses and insurance reimbursements, decreased $2.3 million to $53.3 million in the first quarter of 2015 compared to the first quarter of 2014. On a per Boe basis, lease operating expenses decreased to $12.13 per Boe in the first quarter of 2015 compared to $12.76 per Boe in the first quarter of 2014. On a component basis, facilities maintenance expenses decreased $2.8 million due to reduced activity at multiple offshore locations. Workover expenses decreased $2.1 million primarily due to lower onshore activity. Partially offsetting these decreases, base lease operating expenses increased $2.0 million primarily due to increased costs related to the acquisition of the Woodside Properties (Neptune field). Hurricane related insurance reimbursements decreased $0.5 million and insurance premiums increased $0.1 million between the two periods.

Production taxes. Production taxes decreased $1.4 million to $0.6 million for the first quarter of 2015 compared to the first quarter of 2014. The decrease is primarily due to lower revenues for onshore operations and the Fairway state water operations. In addition, a credit was recorded in the first quarter of 2015 after the settlement of an audit with the State of Alabama. Most of our production is from federal waters where no production taxes are imposed. Our onshore and state water operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased $0.5 million to $4.8 million for the first quarter of 2015 compared to the first quarter of 2014.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased slightly to $28.55 per Boe for the first quarter of 2015 from $28.29 per Boe for the first quarter of 2014. On a nominal basis, DD&A increased to $125.5 million for the first quarter of 2015 from $123.3 million for the first quarter of 2014 due to increased production and an increase in the DD&A per BOE rate. The DD&A per Boe rate increased primarily due to the effect of deep water investments, which have large timing differences between when capital expenditures are incurred and reserves are booked. Two other factors had effects on the DD&A per BOE rate. The first is the lowering of proved reserve quantities used to calculate the rate. Per guidance, the unweighted rolling twelve-month average of first-day-of-the-month commodity prices for oil and natural gas prices are used to estimate future revenues of the proved reserves. The average commodity prices decreased in the first quarter of 2015 compared to the year-end 2014 average prices. These lower average prices caused certain reserves to be assessed as uneconomic and resulted in being removed (or “debooked”), causing a 3% decrease in quantities of proved reserves from 2014 year-end. The second factor is estimated future development costs, which were lowered in light of reduced rates being charged by service companies and reductions in the capital budget.

Ceiling test write-down of oil and natural gas properties. For the first quarter of 2015, we recorded a non-cash ceiling test write-down of $260.4 million as the book value of our oil and natural gas properties exceeded the ceiling test limit. The decrease was primarily due to decreases in prices for all three commodities we sell, which are crude oil, NGLs and natural gas. No ceiling test write-down was incurred in the first quarter of 2014. See Financial Statements - 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.

General and administrative expenses. G&A decreased to $20.8 million for the first quarter of 2015 from $23.6 million for the first quarter of 2014 primarily due to lower incentive compensation expenses, partially offset by lower billings to third-parties for joint venture arrangements. G&A on a per Boe basis was $4.72 per Boe for the first quarter of 2015, compared to $5.41 per Boe for the first quarter of 2014.

Derivative (gain) loss. For the first quarter of 2015, there was no derivative gain or loss as no derivative contracts were open during this period. For the first quarter of 2014, derivative net losses were $7.5 million.

Interest expense. Interest expense incurred for the first quarter of 2015 and 2014 was $22.9 million and $21.5 million, respectively. The increase was primarily attributable to a higher average balance on our revolving bank credit facility in the first quarter of 2015 compared to the first quarter of 2014. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both periods. During the first quarter of 2015 and 2014, $1.8 million and $2.1million, respectively, of interest was capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying certain unevaluated properties to the full cost pool during the fourth quarter of 2014.

Income tax expense. Our income tax benefit for the first quarter of 2015 was $103.6 million compared to income tax expense of $6.6 million for the first quarter of 2014, attributable to a pre-tax loss for the first quarter of 2015 compared to pre-tax income for the first quarter of 2014. Our annualized effective tax rate for the first quarter of 2015 was 28.9% and differs from the federal statutory rate of 35% due to the effect of a valuation allowance for our deferred tax assets. Our effective tax rate for the first quarter of 2014 was 37.3% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes and other permanent items.

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 and make related interest payments. 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.

Cash flow and working capital. Net cash provided by operating activities for the first quarter of 2015 was $0.7 million compared to $118.5 million for the first quarter of 2014. Cash flows from operating activities, before changes in working capital and ARO settlements, were $30.2 million in the first quarter of 2015, a decrease of $117.7 million compared to the $147.9 million generated during the first quarter of 2014. The change in cash flows excluding working capital and ARO settlements was primarily due to lower realized prices for all our commodities - oil, NGLs and natural gas. Our combined average realized sales price per Boe decreased 50.8%. Combined production of oil, NGLs and natural gas on a Boe basis increased 0.8% for the first quarter of 2015 compared to the first quarter of 2014.

The changes in working capital and ARO settlements were basically flat between the two periods, reducing net cash provided by operating activities by approximately $29.4 million each period. The decrease was due to changes in accounts payable, accrued liabilities and ARO settlements, partially offset by changes in receivables, prepaid assets and other assets.

Net cash used in investing activities during the first quarter of 2015 and 2014 was $83.0 million and $95.3 million, respectively, which represents our investments in both offshore and onshore oil and gas properties. There were no acquisitions of significance completed in either period.

Net cash provided by financing activities was $67.0 million for the first quarter of 2015 and net cash used in financing activities was $18.6 million for the first quarter of 2014. The net cash provided for the first quarter of 2015 was attributable to net borrowings on our revolving bank credit facility. The net cash used for the first quarter of 2014 was primarily attributable to net repayments of $11.0 million on our revolving bank credit facility and dividend payments of $7.6 million.

At March 31, 2015, we had a cash balance of $8.4 million and $235.4 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $750.0 million as of March 31, 2015. During April 2015, the borrowing base was revised to $600.0 million, which also reduced undrawn capacity on the revolving bank credit facility by the corresponding $150.0 million reduction.

Credit Agreement and long-term debt. At March 31, 2015 and December 31, 2014, $514.0 million and $447.0 million, respectively, were outstanding under our revolving bank credit facility. During the three months ended March 31, 2015, the outstanding borrowings on our revolving bank credit facility ranged from $447.0 million to $514.0 million. In April 2015, we entered into the Amendment to the Original Credit Agreement, which is more fully described in Financial Statements - Note 12 - Subsequent Events under Part I, Item 1 of this Form 10-Q. At March 31, 2015 and December 31, 2014, $900.0 million in aggregate principal amount of our 8.50% Senior Notes was outstanding. We believe that cash provided by operations, borrowings available under our revolving bank credit facility and other external sources of liquidity should be sufficient to fund our ongoing cash requirements, but additional financing could be required if we are successful in finding suitable acquisitions and for future development activities.

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 Credit Agreement contains financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on several financial ratios, as defined in the Credit Agreement. The Amendment revised these financial covenants to be less restrictive compared to the Original Credit Agreement and the revisions to the financial ratios were made retroactively to March 31, 2015. See Financial Statements - Note 12 - Subsequent Events under Part I, Item 1 of this Form 10-Q for information on the financial ratios and additional information. We were in compliance with all applicable covenants of the Credit Agreement and the 8.50% Senior Notes as of March 31, 2015.

On May 5, 2015, we announced the pricing and marketing of a $300.0 million five-year second-lien term loan, but the transaction had not closed prior to the filing of this Form 10-Q and there is no assurance that the term loan will be finalized and closed. The term loan is described in Financial Statements – Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q. If consummated, the net borrowings will be used to repay a portion of the borrowings under the revolving bank credit facility.

If commodity prices decline or remain similar to our average prices realized in the first quarter of 2015 for an extended period of time, our future revenues, earnings and liquidity would be negatively impacted, as would our ability to invest for future reserve growth. Other potential negative impacts of such price weakness include: a) our ability to meet our financial covenants in future periods, b) recognizing additional ceiling test write-downs of the carrying value of our oil and gas properties, and c) reductions in our proved reserves. As a result, these events could force us to seek alternate financing, such as, a) securities offerings, b) joint ventures, and c) sales of properties. These events could also force us to engage the lenders under the Credit Agreement in discussions regarding further amendments. We may have to reduce future cash outlays for capital expenditures and other activities until such time as market conditions recover or stabilize. Realization of any of these events would depend on the longevity and severity of such price weakness.

Derivatives. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of our oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of March 31, 2015, we did not have any open derivative instruments.

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, 2014. In June 2014, the Fifth Circuit reversed a lower court's ruling and compelled our insurance underwriters to reimburse costs incurred by us for removal of wreck related to damages we incurred during Hurricane Ike. Several of the underwriters have not paid 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. After receiving reimbursements applied against our remaining Energy Package limits, reimbursement from certain underwriters of the Excess Policies of approximately $10 million and adjustments to claims, the estimated potential reimbursement of removal-of-wreck costs is approximately $30 million, plus interest, attorney fees and damages, if any. Given the Fifth Circuit's ruling, we expect to be reimbursed and compensated for all these costs, interest, fees and damages. See Financial Statements - Note 11 - Contingencies under Part I, Item 1 of this Form 10-Q.

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 have $75.0 million of named windstorm (hurricane and tropical storm) coverage for certain of our offshore properties and wells and an additional $75.0 million for certain properties and wells at our higher value fields. We have $50.0 million of named windstorm coverage for our lower value offshore properties for the cost of removal in excess of scheduled ARO amounts. The well control, named windstorm and physical damage coverage is effective until June 1, 2015. A per-occurrence retention amount of $30.0 million for named windstorm events must be satisfied by us before our insurers will indemnify us for losses and we co-insure 15% of our named windstorm coverage. We also have other smaller per-occurrence retention amounts for various other events. Coverage for pollution causing a negative environmental impact is provided under the well control and named windstorm sections of the policy.

All of our Gulf of Mexico properties with estimated future net revenues are covered under our current insurance policies for named windstorm damage. The risk exposure varies per property and we have exposure for applicable retentions, co-insurance amounts and coverage limits.

Our general and excess liability policies are effective until May 1, 2016 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. We have a separate builder's risk and liability policy for certain non-operated properties for platforms and drilling operations under construction, which has coverage net to our interest of $137.0 million and $50.0 million, respectively, with retentions ranging from $0.1 to $0.3 million for different events and is effective until the estimated completion date of December 31, 2015. 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. We qualify to self-insure for $50.0 million of this amount and the remaining $100.0 million is covered by insurance.

Although we were able to renew our general and excess liability policies and expect to renew our Energy Package in May 2015, in the future, our insurers may not continue to offer this type and level of coverage to us, 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, and the results of our exploration and development activities. The following table presents our capital expenditures for exploration, development and other leasehold costs and acquisitions:

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Exploration [(1)]	$28,336	$51,427
Development [(1)]	48,735	30,796
Seismic, capitalized interest, acquisition adjustments and other	5,694	12,844
Acquisitions and investments in oil and gas property/equipment	$82,765	$95,067

(1) Reported geographically in the subsequent table.

The following table presents our exploration and development capital expenditures geographically:

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Conventional shelf	$7,992	$18,625
Deepwater	60,604	13,120
Deep shelf	2	21,968
Onshore	8,473	28,510
Exploration and development capital expenditures	$77,071	$82,223

Our capital expenditures for the first quarter of 2015 and 2014 were financed by cash flow from operating activities, borrowings on our revolving bank credit facility and cash on hand.

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

	Three Months Ended March 31,			
	2015		2014	
	Gross	Net	Gross	Net
Development wells:				
Offshore wells:				
Productive	—	—	—	—
Non-productive	—	—	—	—
Onshore wells:				
Productive	3	2.3	4	4.0
Non-productive	—	—	—	—
Total development wells	3	2.3	4	4.0
Exploration wells:				
Offshore wells:				
Productive	2	0.4	2	1.2
Non-productive	—	—	—	—
Onshore wells:				
Productive	1	1.0	6	6.0
Non-productive	—	—	—	—
Total exploration wells	3	1.4	8	7.2
Total wells	6	3.7	12	11.2

Exploration activities. During the first quarter of 2015, the two offshore exploration wells completed were the #1 and #2 wells at Mississippi Canyon 782 (Dantzler), with first production expected in early 2016. During the first quarter of 2015, the one exploration onshore well was a horizontal well, which is currently producing. Subsequent to March 31, 2015, we had one offshore well being drilled, two offshore wells awaiting completion, seven onshore wells awaiting completion and two onshore wells being evaluated. During the first quarter of 2014, the completion operations on the Mississippi Canyon 698 (Big Bend) well were finalized, with first production expected in late 2015.

Acquisitions and funding. We intend to continue to pursue acquisitions and joint venture opportunities during 2015 and beyond should we identify attractive opportunities and obtain suitable financing. For example, during 2014, we completed the acquisition of the Woodside Properties and we completed the acquisition of the remaining interest in the Fairway Properties as described in Financial Statements - Note 2 - Acquisitions and Divestitures under Part I, Item 1of this Form 10-Q. We are actively evaluating opportunities and seek to complement our drilling and development projects with acquisitions providing acceptable rates of return.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. During the three months ended March 31, 2015, we did not have any divestitures of significance.

Capital Expenditure Budget for 2015. Our current capital expenditure budget for 2015 is $200 million, not including any potential acquisitions. The 2015 budget is being allotted as follows: 38% for exploration, 61% for development and less than 1% for other items. Geographically, the budget is split 92% for offshore and 8% for onshore, with the substantial majority of offshore dedicated to the deepwater. Through April 2015, we have not closed any acquisitions, but we continue to evaluate opportunities as they arise. We anticipate funding our 2015 capital budget, any potential acquisitions and other expenditures with cash flow from operating activities, cash on hand and borrowings under our revolving bank credit facility. Our 2015 capital budget is subject to change as conditions warrant. We strive to be as flexible as possible and believe this strategy holds the best promise for value creation, growth and managing the volatility inherent in our business.

Income taxes. During the three months ended March 31, 2015 and 2014, we did not make any income tax payments nor receive any refunds of significance. For the remainder of 2015, we expect a substantial amount of our income tax will be deferred and expect payments, if any, to be primarily related to state taxes. We have $516.4 million of Federal net operating loss carryforwards (tax basis) available to offset future federal taxable income in 2015 and forward. We also have $12.1 million of alternative minimum tax credit carryforwards (tax basis) available to be utilized in 2015 and forward.

Dividends. Pursuant to the Credit Agreement, the regular quarterly dividend is suspended until June 2016, and may be suspended further depending on certain financial covenants. See Note 12 for additional information.

Capital markets and impact on liquidity. As previously discussed, we have priced and marketed a $300.0 million five-year second-lien term loan, but have not closed on the transaction as of the date of filing this Form 10-Q. The net borrowings will be used to repay a portion of the borrowings under the revolving bank credit facility. Upon issuance of the term loan, the borrowing base of the revolving bank credit facility will be reduced from $600.0 million to $500.0 million pursuant to the terms of the Credit Agreement, as amended. Our expectation is the transaction will close in May 2015, but there is no assurance that the term loan will be finalized and made. If the transaction is not consummated, our current plans are to obtain similar financing in 2015, which may be collateralized on a subordinate level to the debt under the Credit Agreement or may be unsecured debt. We have assessed our financial condition, our current liquidity arrangement under the Credit Agreement (as amended), the pending term loan transaction, the current capital and credit markets and options given different scenarios of commodity prices and believe we will have adequate liquidity to fund our operations through March 31, 2016; however, we cannot predict how an extended period of low commodity prices will affect our operations and liquidity levels.

Contractual obligations. Updated information on certain contractual obligations is provided in Financial Statements - Note 3 - Asset Retirement Obligations and Note 12 - Subsequent Events under Part I, Item 1 of this Form 10-Q. As of March 31, 2015, drilling rig commitments were approximately $9.3 million compared to $12.6 million as of December 31, 2014. The current drilling rig commitments expire within one year from March 31, 2015. Except for scheduled utilization, other contractual obligations as of March 31, 2015 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, 2014.

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, 2014. Also refer to Financial Statements - Note 1 - Basis of Presentation under Part 1, Item 1 of this Form 10-Q.

Recent Accounting Pronouncements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the three months ended March 31, 2015 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, 2014. 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, 2014.

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 March 31, 2015, we did not have any open derivative contracts. During 2014, we used crude oil derivatives related to a portion of our production. Pursuant to the Credit Agreement, we are required to establish by June 1, 2015 minimum hedge positions of 25% of estimated oil and gas production for the period of June 1 to December 31, 2015 and 35% of estimated production for 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 and Note 12 - Subsequent Events under Part I, Item 1 of this Form 10-Q for additional information.

Interest Rate Risk. As of March 31, 2015, we had $514.0 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 March 31, 2015, we did 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 March 31, 2015 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 March 31, 2015, 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, 2014, 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 recent decrease 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, 2014 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, 2014, except as set forth below.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of saltwater gathered from our drilling and production activities, which could have a material adverse effect on our business.

We dispose of large volumes of wastewater generated by our Permian Basin drilling and production activities. This wastewater is frequently co-produced with oil and natural gas and is very salty. The most common method for disposing of this "produced water" is by injection into deep disposal wells, pursuant to permits issued by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements. A few recent studies have indicated that the injection of large volumes of produced water into certain underground formations may induce low-level seismic activity that can on occasion be felt by persons on the ground surface. In response public concerns associated with these ground tremors, regulators in some states have begun to take actions to prevent injection wells from inducing excessive seismicity. For example, in October 2014, the Texas Railroad Commission (“TRC”) published a new rule governing permitting or re-permitting of disposal wells that requires, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permit holder or applicant fails to demonstrate that the injected fluids will be confined to the disposal zone or if scientific data indicates the disposal well is likely to contribute to seismic activity, then the TRC may modify or suspend an existing permit or deny the application for a new permit. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of wastewater produced by our drilling and production activities could increase our costs of disposing of produced water and have a material adverse effect on our business, financial condition and results of operations.

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 May 7, 2015.

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 24, 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 herewith.

** Furnished herewith.

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