W&T OFFSHORE INC
Form 10-Q
May 08, 2014

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, 2014

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	77046-0908

(Address of principal executive offices) (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 5, 2014, there were 75,634,246 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2014	December 31, 2013
	(In thousands, except per share data)	
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$20,335	$15,800
Receivables:		
Oil and natural gas sales	93,937	96,752
Joint interest and other	27,588	27,984
Income tax	3,155	3,120
Total receivables	124,680	127,856
Prepaid expenses and other assets	27,015	29,946
Total current assets	172,030	173,602
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which $118,125 at March 31, 2014 and $116,612 at December 31, 2013 were excluded from amortization)	7,443,733	7,339,097
Furniture, fixtures and other	21,633	21,431
Total property and equipment	7,465,366	7,360,528
Less accumulated depreciation, depletion and amortization	5,202,966	5,084,704
Net property and equipment	2,262,400	2,275,824
Restricted deposits for asset retirement obligations	39,961	37,421
Other assets	20,213	20,455
Total assets	$2,494,604	$2,507,302
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$115,344	$145,212
Undistributed oil and natural gas proceeds	38,312	42,107
Asset retirement obligations	68,679	77,785
Accrued liabilities	43,698	28,000
Total current liabilities	266,033	293,104
Long-term debt, less current maturities	1,193,847	1,205,421
Asset retirement obligations, less current portion	285,720	276,637
Deferred income taxes	188,183	178,142
Other liabilities	13,497	13,388
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at March 31, 2014 and December 31, 2013	—	—

Common stock, $0.00001 par value; 118,330,000 shares authorized; 78,503,419 issued and 75,634,246 outstanding at March 31, 2014; 78,460,872 issued and 75,591,699 outstanding at December 31, 2013	1	1
Additional paid-in capital	406,752	403,564
Retained earnings	164,738	161,212
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	547,324	540,610
Total liabilities and shareholders' equity	$2,494,604	$2,507,302

See Notes to Condensed Consolidated Financial Statements.

1

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31,	
	2014	2013
	(In thousands except per share data) (Unaudited)	
Revenues	$254,516	$259,222
Operating costs and expenses:		
Lease operating expenses	55,617	59,341
Production taxes	1,992	1,789
Gathering and transportation	5,296	4,444
Depreciation, depletion, amortization and accretion	123,306	108,872
General and administrative expenses	23,588	21,087
Derivative loss	7,492	3,368
Total costs and expenses	217,291	198,901
Operating income	37,225	60,321
Interest expense:		
Incurred	21,460	21,234
Capitalized	(2,072)	(2,433)
Income before income tax expense	17,837	41,520
Income tax expense	6,648	14,902
Net income	$11,189	$26,618
Basic and diluted earnings per common share	$0.15	$0.35
Dividends declared per common share	$0.10	$0.08

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	Retained	Treasury Stock		Total Shareholders'
	Shares	Value	Capital	Earnings	Shares	Value	Equity
	(In thousands) (Unaudited)						
Balances at December 31, 2013	75,592	$ 1	$ 403,564	$ 161,212	2,869	$ (24,167)	$ 540,610
Cash dividends	—	—	—	(7,563)	—	—	(7,563)
Share-based compensation	42	—	3,758	—	—	—	3,758
Other	—	—	(570)	(100)	—	—	(670)
Net income	—	—	—	11,189	—	—	11,189
Balances at March 31, 2014	75,634	$ 1	$ 406,752	$ 164,738	2,869	$ (24,167)	$ 547,324

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31, 2014 (In thousands) (Unaudited)			2013		
Operating activities:						
Net income	$	11,189		$	26,618	
Adjustments to reconcile net income to net cash provided by operating activities:						
Depreciation, depletion, amortization and accretion		123,306			108,872	
Amortization of debt issuance costs and premium		187			447	
Share-based compensation		3,758			2,255	
Derivative loss		7,492			3,368	
Cash payments on derivative settlements (realized)		(4,670	)		(4,271	)
Deferred income taxes		6,645			12,507	
Changes in operating assets and liabilities:						
Oil and natural gas receivables		2,815			423	
Joint interest and other receivables		2,286			25,875	
Income taxes		(35	)		2,372	
Prepaid expenses and other assets		2,709			4,911	
Asset retirement obligation settlements		(16,342	)		(23,464	)
Accounts payable, accrued liabilities and other		(20,850	)		9,921	
Net cash provided by operating activities		118,490			169,834	
Investing activities:						
Investment in oil and natural gas properties		(95,067	)		(136,626	)

and equipment				
Purchases of furniture, fixtures and other		(260)		(114)
Net cash used in investing activities		(95,327)		(136,740)
Financing activities:				
Borrowings of long-term debt - revolving bank credit facility		92,000		112,000
Repayments of long-term debt - revolving bank credit facility		(103,000)		(139,000)
Dividends to shareholders		(7,563)		(6,020)
Other		(65)		(42)
Net cash used in financing activities		(18,628)		(33,062)
Increase in cash and cash equivalents		4,535		32
Cash and cash equivalents, beginning of period		15,800		12,245
Cash and cash equivalents, end of period	$	20,335	$	12,277

See Notes to Condensed Consolidated Financial Statements.

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

1. Basis of Presentation

Operations. W&T Offshore, Inc. and subsidiaries, referred to herein as "W&T" 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. (the "Parent Company") and our wholly-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, 2013.

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.

Adjustment related to additional volumes. In January 2014, we identified that we had been receiving an erroneous conversion factor from a third party that had the effect of understating natural gas production at our Viosca Knoll 783 field (Tahoe). The incorrect conversion factor had been used on all natural gas production from the field since we acquired it in 2011. The effect of using this incorrect conversion factor did not affect revenues, operating cash flows or royalty payments to the federal government but did impact reported natural gas production and the calculation of depletion expense. We performed an analysis of the information, assessing both quantitative and qualitative factors, and determined that the impact on our net income reported for quarters in 2013, as well as the impact to our earnings trend, was not material to the previously reported results, thus the adjustment was recognized in the fourth quarter of 2013. The amounts included in the adjustment recognized in the fourth quarter 2013 period which relate to the first quarter of 2013 were: an increase in natural gas production volumes of 264 million cubic feet ("MMcf") (with no corresponding increase in revenue); an increase to depreciation, depletion, amortization and accretion expense ("DD&A") of $0.8 million; and a decrease to net income of $0.5 million.

Recent Accounting Developments. None.

2. Acquisitions and Divestitures

2013 Acquisition

On October 17, 2013, W&T Offshore, Inc. entered into a purchase and sale agreement to acquire certain oil and natural gas property interests from Callon Petroleum Operating Company ("Callon"). Pursuant to the purchase and sale agreement, transfers of certain properties that had no preferential rights were consummated on November 5, 2013 and transfers of certain properties subject to preferential rights, of which third-parties declined to exercise their preferential rights, were consummated on December 4, 2013. The properties acquired from Callon (the "Callon Properties") consist of a 15% working interest in the Medusa field (deepwater Mississippi Canyon blocks 582 and 583), interest in associated production facilities and various interests in other non-operated fields. All of the Callon Properties are located in the Gulf of Mexico. The effective date of the transaction was July 1, 2013. The transaction included customary adjustments for the effective date, certain closing adjustments and we assumed the related ARO. A net purchase price adjustment of $0.2 million reduction was recorded during the three months ended March 31, 2014. The purchase price is expected to be finalized in the second quarter of 2014. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

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

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

Cash consideration:	
Evaluated properties including equipment	$73,007
Unevaluated properties	9,248
Sub-total cash consideration	82,255
Non-cash consideration:	
Asset retirement obligations - current	90
Asset retirement obligations - non-current	4,143
Sub-total non-cash consideration	4,233
Total consideration	$86,488

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 Callon Properties acquisition.

2013 Acquisition — Revenues, Net Income and Pro Forma Financial Information — Unaudited

The Callon Properties were not included in our consolidated results until the respective property transfer dates, which occurred during the fourth quarter of 2013. For the three months ended March 31, 2014, the Callon Properties accounted for $8.7 million of revenues, $0.9 million of direct operating expenses, $3.5 million of DD&A and $1.5 million of income taxes, resulting in $2.8 million of net income. The net income attributable to the Callon 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 Callon Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate. There were no expenses associated with acquisition activities and transition activities related to the acquisition of the Callon Properties for the three months ended March 31, 2013.

Consistent with the computation of pro forma financial information presented in Item 8, Financial Statements and Supplementary Data, in the Annual Report on Form 10-K for the year end December 31, 2013, the unaudited pro forma financial information was computed as if the acquisition of the Callon Properties had been completed on January 1, 2012. 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 the interim periods, the Callon Properties’ audited historical financial statement for 2012 and the Callon Properties’ unaudited historical financial statements for the interim periods.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Callon Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2012. If the transaction had been in effect for the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than Callon; the realized sales prices for oil, natural gas liquids ("NGLs") and natural gas may have been different; and the costs of operating the Callon Properties may have been different.

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

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

	Three Months Ended March 31, 2013
Revenue	$270,575
Net income	29,618
Basic and diluted earnings per common share	0.39

For the pro forma financial information, certain information was derived from financial records and certain information was estimated.

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

	Three Months Ended March 31, 2013
Revenues (a)	$11,353
Direct operating expenses (a)	2,206
DD&A (b)	4,205
Interest expense (c)	411
Capitalized interest (d)	(84)
Income taxes expense (e)	1,615

The sources of information and significant assumptions are described below:

(a) Revenues and direct operating expenses for the Callon Properties were derived from the historical financial records of Callon.
(b) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Callon 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) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $82.3 million, which equates to the cash component of the transaction, and an interest rate

of 2.0%, which equates to the rates applied to incremental borrowings on the revolving bank credit facility.

(d) 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.

(e) 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.

2013 Divestitures. On July 11, 2013, we sold our non-operated working interest in two offshore fields located in the Gulf of Mexico; the Green Canyon 60 field and the Green Canyon 19 field. The effective date was October 1, 2011 and we retained the deep rights in both fields. Due to the length of time from the effective date, we paid $4.3 million to sell the properties as revenues exceeded operating expenses and the purchase price for the period between the effective date and the close date. In connection with the sale, we reversed $15.6 million of our ARO.

On September 26, 2013, we sold our working interests in the West Delta area block 29 with an effective date of January 1, 2013. The property is located in the Gulf of Mexico. Including adjustments for the effective date, the net proceeds were $16.5 million. The transaction was structured as a like-kind exchange under the Internal Revenue Service Code ("IRC") Section 1031 and other applicable regulations, with funds held by a qualified intermediary until replacement purchases are made. Replacement purchases were made in 2013, which were within the replacement periods as defined under the IRC. In connection with this sale, we reversed $3.9 million of ARO.

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, 2013	$354,422
Liabilities settled	(16,342)
Accretion of discount	4,983
Liabilities incurred	4,277
Revisions of estimated liabilities (1)	7,059
Balance, March 31, 2014	354,399
Less current portion	68,679
Long-term	$285,720

(1) Revisions were primarily due to increased estimates related to work requiring coiled tubing at two locations and removal of a platform at one location.

4. Derivative Financial Instruments

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

In accordance with GAAP, we record each derivative contract on the balance sheet as an asset or a liability at its fair value. For additional information about fair value measurements, refer to Note 6. We have elected not to designate our commodity derivative contracts as hedging instruments; therefore, all changes in the fair value of derivative contracts are recognized currently in earnings. The cash flows of all of our commodity derivative contracts are included in Net cash provided by operating activities on the statements of cash flows.

Commodity Derivatives. We have entered into commodity swap contracts to manage a portion of our exposure to commodity price risk from sales of oil through December 2014. While these contracts are intended to reduce the effects of price volatility, they may also limit future income from favorable price movements. During the three months ended March 31, 2014 and during 2013, our derivative contracts consisted entirely of crude oil swap contracts. The crude oil swap contracts are comprised of a portion based on Brent crude oil prices, a portion based on West Texas Intermediate (“WTI”) crude oil prices and a portion based on Light Louisiana Sweet (“LLS”) crude oil prices. The Brent based swap contracts are priced off the Brent crude oil price quoted on the IntercontinentalExchange, known as ICE. The WTI based swap contracts are priced off the New York Mercantile Exchange, known as NYMEX. The LLS based swap contracts are priced from data provided by Argus, an independent media organization. Although our Gulf of Mexico crude oil is based off the WTI crude oil price plus a premium, the realized prices received for our Gulf of Mexico crude oil, up until October 2013, have been closer to the Brent crude oil price because of competition with foreign supplied crude oil, which is based off the Brent crude oil price. Therefore, a portion of the swap oil contracts are priced off the Brent crude oil price to mitigate a portion of the price risk associated with our Gulf of Mexico crude oil production.

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

As of March 31, 2014, our open commodity derivative contracts were as follows:

	Swaps – Oil Priced off Brent (ICE)		Priced off WTI (NYMEX)		Priced off LLS (ARGUS)	
Termination Period	Notional Quantity (Bbls)	Weighted-Average Contract Price	Notional Quantity (Bbls)	Weighted-Average Contract Price	Notional Quantity (Bbls)	Weighted-Average Contract Price
2014: 2nd Quarter	172,900	$ 97.38	353,000	$ 97.04	637,000	$ 97.83
3rd Quarter	165,600	97.38	62,000	97.01	828,000	97.69
4th Quarter	156,400	97.37	—	—	460,000	98.12
	494,900	$ 97.38	415,000	$ 97.04	1,925,000	$ 97.84

Bbls = barrels

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

	March 31, 2014	December 31, 2013
Prepaid and other assets	$—	$ 141
Accrued liabilities	12,104	9,423

Changes in the fair value of our commodity derivative contracts are recognized currently in earnings and were as follows (in thousands):

	Three Months Ended March 31, 2014	2013
Derivative (gain) loss:		
Realized	$ 4,670	$4,271
Unrealized	2,822	(903)
Total	$ 7,492	$3,368

Offsetting Commodity Derivatives. As of March 31, 2014 and December 31, 2013, all of our derivative agreements allowed for netting of derivative gains and losses upon settlement. In general, the terms of the agreements provide for offsetting of amounts payable or receivable between us and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency. If an event of default were to occur causing an acceleration of payment under our revolving bank credit facility, that event may also trigger an acceleration of settlement of our derivative instruments. If we were required to settle all of our open derivative instruments, we would be able to net payments and receipts per counterparty pursuant to the derivative agreements. Although our derivative agreements allow for netting, which would allow for recording assets and liabilities per counterparty on a net basis, we account for our derivative contracts on a gross basis per contract as either an asset or liability.

The following table provides a reconciliation of the gross assets and liabilities reflected in the balance sheet and the potential effects of master netting agreements on the fair value of open derivative contracts (in thousands):

	March 31, 2014		December 31, 2013	
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amounts presented in the balance sheet	$—	$ 12,104	$ 141	$ 9,423
Amounts not offset in the balance sheet	—	—	(141)	(141)
Net Amounts	$—	$ 12,104	$—	$ 9,282

5. Long-Term Debt

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

	March 31, 2014	December 31, 2013
8.50% Senior Notes	$900,000	$900,000
Debt premiums, net of amortization	14,847	15,421
Revolving bank credit facility	279,000	290,000
Total long-term debt	1,193,847	1,205,421
Current maturities of long-term debt	—	—
Long term debt, less current maturities	$1,193,847	$1,205,421

At March 31, 2014 and December 31, 2013, 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, 2014.

The Fifth Amended and Restated Credit Agreement (the “Credit Agreement”) governs our revolving bank credit facility and terminates 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 March 31, 2014 and December 31, 2013, we had $0.4 million of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 2.8% for the three months ended March 31, 2014 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, 2014, our borrowing base was $800.0 million and our borrowing availability was $520.6 million. See Note 12 for information regarding a change of the borrowing base to $750.0 million subsequent to March 31, 2014.

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 and a maximum leverage ratio, each as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of March 31, 2014.

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

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

6. Fair Value Measurements

We measure the fair value of our 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 and 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 derivative financial instruments, 8.50% Senior Notes and revolving bank credit facility (in thousands).

		March 31, 2014		December 31, 2013	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$—	$ 12,104	$ 141	$ 9,423
8.50% Senior Notes	Level 2	—	974,250	—	962,460
Revolving bank credit facility	Level 2	—	279,000	—	290,000

As described in Note 4, our derivative financial instruments are reported in the balance sheet at fair value and changes in fair value are recognized currently in earnings. 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 the three months ended March 31, 2014, and in 2013 and 2012, the Company granted restricted stock units ("RSUs") to certain of its employees. RSUs are a long-term compensation component of the Plan, which are granted to 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 the three months ended March 31, 2014, RSUs granted were subject to 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. Adjustments range from 0% to 100% dependent upon actual results compared against pre-defined performance levels.

During 2013, RSUs granted were subject to 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, was approximately at target for 2013 Adjusted EBITDA Margin and was below target for TSR ranking.

During 2012, RSUs granted were subject to a combination of performance criteria, which was comprised of: (i) earnings per share for 2012; and (ii) the Company's TSR ranking against peer companies' TSR for 2012, 2013 and January 1, 2014 to October 31, 2014. Pursuant to the Plan, discretionary authority was exercised for certain non-executive employees, which reduced the forfeitures that would have occurred through application of the pre-defined performance measurement.

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 2012 will vest in December 2014 to eligible employees.

The compensation related to the 2013 annual incentive plan for the Chief Executive Officer ("CEO") was determined based on pre-defined company and individual performance measures pursuant to the terms of his award and was settled in shares of common stock in March 2014. The 2014 annual incentive plan award for the CEO will be settled in shares of common stock based on a price of $14.66 per share, subject to pre-defined performance measures and approval of the Compensation Committee. As the number of shares cannot be determined and a grant has not yet been made, the CEO's 2014 award is accounted for as a liability award and adjusted to fair value using the Company's closing price at the end of each reporting period. The performance measures for the CEO's award were the same as the performance measures established for the other eligible Company employees for 2014 and 2013, respectively.

Under the Director Compensation Plan, restricted stock was granted to the Company's non-employee directors during 2013 and prior years. The restricted stock is subject to service conditions and vesting occurs at the end of specified service periods.

At March 31, 2014, there were 5,036,436 shares of common stock available for issuance in satisfaction of awards under the Plan and 519,379 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 stock or common stock is granted. RSUs will reduce the shares available in the Plan only when RSUs are settled in shares of common stock. 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. As of March 31, 2014, all of the unvested shares of restricted stock ("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, 2014 are expected to vest as follows:

	Restricted Shares
2014	19,445
2015	15,245

2016	9,150
Total	43,840

There were no grants, forfeitures or vesting of Restricted Shares during the three months ended March 31, 2014 and 2013.

Awards Based on Restricted Stock Units. As of March 31, 2014, the Company had outstanding RSUs issued to certain employees. As described above, the RSUs granted during the three months ended March 31, 2014 are subject to pre-defined performance measures which cannot be determined at this time; therefore, no portion has been determined to be eligible for vesting as of March 31, 2014. A portion of the RSUs granted during 2013 and 2012 remains subject to certain pre-defined performance measures of TSR for the defined periods in 2014 and 2015; therefore, this portion may be adjusted upon determination of the respective performance. These RSU adjustments related to TSR performance will not affect unrecognized expense, as the fair value of the portion related to market-based awards (TSR) was established at the date of grant (described below) and actual performance does not affect expense recognition for this portion. The portion of RSUs subject to performance measurement and adjustment ranges are disclosed in the second table below.

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

The fair value for the RSUs granted during the three months ended March 31, 2014 was determined using the Company's closing price on the grant date. The fair value for the 2013 RSUs was determined separately for the component related to the Company specific performance measures (Adjusted EBITDA and Adjusted EBITDA Margin) and the component related to TSR targets. The fair value of the 2013 RSUs component related to the Company specific performance measures was determined using the Company's closing price on the grant date. 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 (84%) to 95%. The expected volatilities, expected dividends and correlation factors were developed using historical data.

A methodology similar to that employed for the 2013 RSUs was used to determine the fair value for the 2012 RSUs. The inputs used in the probabilistic model for the Company and the peer companies were: average closing stock prices during January 2012; risk-free interest rates using the LIBOR ranging from 0.15% to 0.72% over the service period; expected volatilities ranging from 33% to 74%; expected dividend yields ranging from 0.0% to 2.5%; and correlation factors ranging from (67%) to 94%. The expected volatilities, expected dividends and correlation factors were developed using historical data.

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 2014 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted-Average Grant Date Fair Value Per Unit
Nonvested, December 31, 2013	1,331,753	$ 14.96
Granted	1,150,233	16.82
Vested	—	—
Forfeited	(12,521)	15.10
Nonvested, March 31, 2014	2,469,465	$ 15.82

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, 2014 potentially eligible to vest are listed in the table below:

	RSUs
2014 - subject to service requirements	355,864
2014 - subject to service and other requirements (1)	67,399
2015 - subject to service requirements	713,547
2015 - subject to service and other requirements (2)	182,422
2016 - subject to service and other requirements (3)	1,150,233
Total	2,469,465

(1) In addition to service requirements, these RSUs are also subject to TSR performance requirements not yet measureable, with awards ranging from 0% to 150% of amounts granted.
(2) 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.
(3) In addition to service requirements, these RSUs are also subject to Company specific performance requirements not yet measureable, with awards ranging from 0% to 100% of amounts granted.

The grant date fair value of RSUs granted during the three months ended March 31, 2014 was $19.4 million. There were no grants of RSUs during the three months ended March 31, 2013. During the three months ended March 31, 2014 and 2013, there was no vesting of RSUs.

Awards Based on Common Stock. A grant and issuance of 42,547 shares of common stock was made in March 2014 to the CEO pursuant to the terms of his 2013 annual incentive compensation award. The number of shares was determined after deductions for withholding and payroll taxes and the shares were valued at the Company's closing price as of the date of grant.

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,	
	2014	2013
Share-based compensation expense from:		
Restricted stock	$99	$99
Restricted stock units	2,537	2,156
Common stock	1,122	—
Total	$3,758	$2,255
Share-based compensation tax benefit:		
Tax benefit computed at the statutory rate	$1,315	$789

Unrecognized Share-Based Compensation. As of March 31, 2014, unrecognized share-based compensation expense related to our awards of Restricted Shares, RSUs and common stock was $0.4 million, $27.0 million and $0.9 million, respectively. Unrecognized share-based compensation expense will be recognized through April 2016 for Restricted Shares, November 2016 for RSUs and February 2015 for awards based on common shares.

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 grant for 2013 payable in 2014 was 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.

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,

	2014	2013
Share-based compensation included in:		
General and administrative (1)	$3,758	$2,255
Cash-based incentive compensation included in:		
Lease operating expense	1,302	1,393
General and administrative (1)	1,781	3,530
Total charged to operating income	$6,841	$7,178

(1) Reclassified $0.7 million from cash-based incentive compensation expense to share-based compensation expense in the three months ended March 31, 2014 related to the CEO's 2013 award.

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

8. Income Taxes

Income tax expense of $6.6 million and $14.9 million was recorded during the three months ended March 31, 2014 and 2013, respectively. 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. The effective tax rate for the three months ended March 31, 2013 was 35.9% and differed from the federal statutory rate primarily as a result of state income taxes.

During 2013, we received refunds of $59.1 million, of which $9.5 million of these refunds have been accounted for as unrecognized tax benefits. We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the three months ended March 31, 2014 and 2013, we had less than $0.1 million of accrued interest expense related to our unrecognized tax benefit. As of March 31, 2014 and December 31, 2013, we had a valuation allowance related to state net operating losses. 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. The tax years from 2010 through 2013 remain open to examination by the tax jurisdictions to which we are subject.

9. Earnings Per Share

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

	Three Months Ended March 31,	
	2014	2013
Net income	$11,189	$26,618
Less portion allocated to nonvested shares	120	281
Net income allocated to common shares	$11,069	$26,337
Weighted-average common shares outstanding	75,556	75,206
Basic and diluted earnings per common share	$0.15	$0.35
Shares excluded as anti-dilutive (weighted-average)	—	870

10. Dividends

During the three months ended March 31, 2014 and 2013, we paid regular cash dividends per common share of $0.10 and $0.08, respectively. On May 6, 2014, our board of directors declared a cash dividend of $0.10 per common share, payable on June 4, 2014 to shareholders of record on May 23, 2014.

11. Contingencies

Notice of Suspension and Debarment. In November 2013, W&T Offshore, Inc., the Parent Company, received a Notice of Suspension and Proposed Debarment and a Notice of Clean Water Act Listing from the U.S. Environmental Protection Agency (the “EPA”). The Notices were directed to only the Parent Company and do not name or apply to our wholly-owned subsidiaries. The first Notice suspends the Parent Company and proposes a three year debarment from participation in future federal contracts, including future federal oil and gas leases, and assistance activities and renders the Parent Company ineligible to receive any federal contracts or approved subcontracts or to act as an agent or representative on behalf of another in such transaction, or receive certain federal benefits. The second Notice provides a narrower prohibition on federal contracts or benefits for the Parent Company. The Notices stemmed from the Parent Company’s previously disclosed plea agreement and corporate conviction on two criminal counts as described in Item 8, Financial Statements and Supplementary Data, in our Annual Report on Form 10-K for the year end December 31, 2013.

The Notices prevent the Parent Company from obtaining federal oil and gas leases, whether at a future lease sale or an existing lease by assignment. The Notices do not affect current or future drilling or production operations or the existing lease ownership of the Parent Company.

The Company does not believe that the regulatory requirements for suspension and debarment exist. The Company has corrected the issues leading to the 2009 offenses that form the basis for suspension and debarment and has been and remains a responsible operator. Suspension is not necessary to protect the Government's business interests. The Company believes the EPA action fails to recognize the Company's compliance with the plea agreement referenced above, our demonstration that the conditions which gave rise to the violations have been corrected and that the Company is a responsible operator acting under a comprehensive environmental and safety compliance program. We have had continuing discussions with the EPA Suspension and Debarment Officials and made filings to contest the limitations in both Notices and seek to remove the suspension in a cooperative fashion as soon as practicable. The timing and ultimate result of these efforts, however, cannot be predicted at this time.

Disqualification of waiver concerning certain supplement bonding requirements from the Bureau of Ocean Energy Management ("BOEM"). In November and December 2013, W&T Offshore, Inc. received letters from the BOEM claiming that it no longer qualifies for a waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging, and abandonment liabilities. These letters pertain to the Parent Company's prior supplemental bonding waiver. Our wholly-owned subsidiary, Energy VI, is not exempt from supplemental bonding under BOEM's procedures and therefore such wholly-owned subsidiary provides supplemental bonding for its plugging and abandonment liabilities. The supplemental bonding requirements are separate and distinct from the suspension and debarment issue described above. The letters notified the Parent Company that it must provide supplemental bonding on certain of its offshore leases, rights of way and easements in the Gulf of Mexico. We believe that this action is without basis and inconsistent with regulatory requirements. We have had and continue to have discussions with representatives of the BOEM regarding this decision in an attempt to resolve this issue. We are also discussing potential additional supplemental bonding requirements that may be required to be met in the event that the BOEM's decision regarding the Parent Company's supplemental bonding waiver is not modified or reversed. While these discussions remain ongoing, in order to preserve our rights, in January 2014 we filed a Petition for Stay Pending Appeal and Request for Interim Relief with the U.S. Department of Interior's Board of Land Appeals. The petition seeks a stay of any supplemental bonding requirements pending the appeal and to reverse BOEM's revocation of W&T Offshore, Inc.'s waiver of supplemental bonding requirements. Initially, we were granted a stay until February 15, 2014 in response to our petition and recently we were granted a stay until June 15, 2014 to facilitate ongoing negotiations. We continue to believe that the Parent Company qualifies for a supplemental bonding waiver.

The Parent Company has transferred certain assets together with associated ARO liability to our wholly-owned subsidiary, Energy VI. These actions were taken to assist the Parent Company in its efforts to obtain from the BOEM a continuation of the waiver of supplemental bonding for the Parent Company. We believe these efforts should result in the BOEM's continuation of our waiver of supplemental bonding. These actions have caused us to obtain additional supplemental bonds for Energy VI related to the ARO for the transferred properties, incurring approximately $0.9 million of additional bond fees. Similar bonds fees will be required every year the bonds are in effect until the properties are plugged and abandoned. To date, letters of credit have not been required to secure supplemental bonding for Energy VI, but it is possible that letters of credit may be required in the future. The revolving bank credit facility allows for the issuance of up to $300.0 million of letters of credit. If we were required to post letters of credit for this purpose, this would utilize a portion of our borrowing capacity available under our revolving bank credit facility.

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, which is substantially in excess of the underpayment. We believe the fine is excessive and extreme considering the circumstances and in relation to the underpayment itself. On April 23, 2014, we filed a request for a hearing on the record and a general denial of ONRR's allegations contained in the notice. We intend to contest the fine to the fullest extent possible. 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, 2014 per authoritative guidance. However, we cannot state with certainty that our estimate of the exposure is accurate concerning this matter.

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 and Liberty Mutual Insurance Co.) filed declaratory judgment actions in the United States District Court for the Southern District of Texas seeking a determination that our Excess Policies do not cover removal-of-wreck and debris claims arising from Hurricane Ike 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 disagree with the Court's ruling and have appealed the decision. As of March 31, 2014, we had not filed any claims under such Excess Policies; however, claims were filed subsequent to March 31, 2014. The amount in dispute is estimated at approximately $46.0 million, of which substantially all has been incurred. Removal-of-wreck costs are recorded in Oil and natural gas properties and equipment on the Condensed Consolidated Balance Sheets. If we are successful in our appeal, any recoveries from claims made on these Excess Policies will be recorded as reductions in this line item, which will reduce our DD&A rate.

Royalties. In 2009, the Company recognized $5.3 million in 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 the third quarter of 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue of $4.7 million in the third quarter of 2010 to reflect this disallowance; however, we disagree with the position taken by the ONRR and we are pursuing our claim to resolve the matter.

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 minimal expenses recognized related to accrued and settled claims, complaints and fines for the three months ended March 31, 2014 and 2013. As of March 31, 2014 and December 31, 2013, we have recorded $0.1 million and $0.2 million, respectively, which are included in Accrued liabilities on the Condensed Consolidated Balance Sheets, for the loss contingencies matters in the normal course of business.

12. Subsequent Events

Borrowing Base. Effective April 17, 2014, the borrowing base and the amount available for borrowing under the revolving bank credit facility was changed to $750.0 million. There were no changes to the terms of the Credit Agreement, such as the maturity date, interest rates, covenants or collateral.

13. Supplemental Guarantor Information

Our payment obligations under the 8.50% Senior Notes and the Credit Agreement (see Note 6) are fully and unconditionally guaranteed by certain of our wholly-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 of the 8.50% Senior Notes as described in the indenture, provided no event of default has occurred and is continuing.

The following unaudited 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.

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

Condensed Consolidating Balance Sheet as of March 31, 2014

	Parent Company (In thousands)	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Assets				
Current assets:				
Cash and cash equivalents	$20,335	$—	$—	$ 20,335
Receivables:				
Oil and natural gas sales	66,314	27,623	—	93,937
Joint interest and other	27,588	—	—	27,588
Income tax	92,708	—	(89,553)	3,155
Total receivables	186,610	27,623	(89,553)	124,680
Prepaid expenses and other assets	21,769	5,246	—	27,015
Total current assets	228,714	32,869	(89,553)	172,030
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,624,335	819,398	—	7,443,733
Furniture, fixtures and other	21,633	—	—	21,633
Total property and equipment	6,645,968	819,398	—	7,465,366
Less accumulated depreciation, depletion and amortization	4,862,077	340,889	—	5,202,966
Net property and equipment	1,783,891	478,509	—	2,262,400
Restricted deposits for asset retirement obligations	39,961	—	—	39,961
Other assets	780,337	518,958	(1,279,082)	20,213
Total assets	$2,832,903	$1,030,336	$(1,368,635)	$2,494,604
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$113,459	$1,885	$—	$115,344
Undistributed oil and natural gas proceeds	37,968	344	—	38,312
Asset retirement obligations	66,080	2,599	—	68,679
Accrued liabilities	—	133,251	(89,553)	43,698
Total current liabilities	217,507	138,079	(89,553)	266,033
Long-term debt, less current maturities	1,193,847	—	—	1,193,847
Asset retirement obligations, less current portion	210,959	74,761	—	285,720
Deferred income taxes	130,811	57,372	—	188,183
Other liabilities	532,455	—	(518,958)	13,497
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	406,752	509,326	(509,326)	406,752
Retained earnings	164,738	250,798	(250,798)	164,738

Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders’ equity	547,324	760,124	(760,124)	547,324
Total liabilities and shareholders’ equity	$ 2,832,903	$ 1,030,336	$ (1,368,635)	$ 2,494,604

19

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

Condensed Consolidating Balance Sheet as of December 31, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$ 15,800	$ —	$ —	$ 15,800
Receivables:				
Oil and natural gas sales	75,486	21,266	—	96,752
Joint interest and other	27,984	—	—	27,984
Income tax	124,393	—	(121,273)	3,120
Total receivables	227,863	21,266	(121,273)	127,856
Prepaid expenses and other assets	23,674	6,272	—	29,946
Total current assets	267,337	27,538	(121,273)	173,602
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,770,396	568,701	—	7,339,097
Furniture, fixtures and other	21,431	—	—	21,431
Total property and equipment	6,791,827	568,701	—	7,360,528
Less accumulated depreciation, depletion and amortization	4,784,932	299,772	—	5,084,704
Net property and equipment	2,006,895	268,929	—	2,275,824
Restricted deposits for asset retirement obligations	37,421	—	—	37,421
Other assets	574,280	427,619	(981,444)	20,455
Total assets	$ 2,885,933	$ 724,086	$ (1,102,717)	$ 2,507,302
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 144,492	$ 720	$ —	$ 145,212
Undistributed oil and natural gas proceeds	41,735	372	—	42,107
Asset retirement obligations	75,977	1,808	—	77,785
Accrued liabilities	28,000	121,273	(121,273)	28,000
Total current liabilities	290,204	124,173	(121,273)	293,104
Long-term debt, less current maturities	1,205,421	—	—	1,205,421
Asset retirement obligations, less current portion	238,270	38,367	—	276,637
Deferred income taxes	170,419	7,723	—	178,142
Other liabilities	441,009	—	(427,621)	13,388
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	403,564	317,776	(317,776)	403,564
Retained earnings	161,212	236,047	(236,047)	161,212

Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders’ equity	540,610	553,823	(553,823)	540,610
Total liabilities and shareholders’ equity	$2,885,933	$ 724,086	$(1,102,717)	$ 2,507,302

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

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$176,657	$ 77,859	$ —	$ 254,516
Operating costs and expenses:				
Lease operating expenses	46,148	9,469	—	55,617
Production taxes	1,992	—	—	1,992
Gathering and transportation	3,984	1,312	—	5,296
Depreciation, depletion, amortization and accretion	81,105	42,201	—	123,306
General and administrative expenses	21,364	2,224	—	23,588
Derivative loss	7,492	—	—	7,492
Total costs and expenses	162,085	55,206	—	217,291
Operating income	14,572	22,653	—	37,225
Earnings of affiliates	14,751	—	(14,751)	—
Interest expense:				
Incurred	21,293	167	—	21,460
Capitalized	(1,905)	(167)	—	(2,072)
Income before income tax expense	9,935	22,653	(14,751)	17,837
Income tax expense	(1,254)	7,902	—	6,648
Net income	$11,189	$ 14,751	$ (14,751)	$ 11,189

Condensed Consolidating Statement of Income for the Three Months Ended March 31, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$209,528	$ 49,694	$ —	$ 259,222
Operating costs and expenses:				
Lease operating expenses	54,529	4,812	—	59,341
Production taxes	1,789	—	—	1,789
Gathering and transportation	3,662	782	—	4,444
Depreciation, depletion, amortization and accretion	86,416	22,456	—	108,872

General and administrative expenses	19,604	1,483	—	21,087
Derivative loss	3,368	—	—	3,368
Total costs and expenses	169,368	29,533	—	198,901
Operating income	40,160	20,161	—	60,321
Earnings of affiliates	13,100	—	(13,100)	—
Interest expense:				
Incurred	21,234	—	—	21,234
Capitalized	(2,433)	—	—	(2,433)
Income before income tax expense	34,459	20,161	(13,100)	41,520
Income tax expense	7,841	7,061	—	14,902
Net income	$26,618	$ 13,100	$ (13,100)	$ 26,618

21

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

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	$ 14,751	$ (14,751)	$ 11,189
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	81,105	42,201	—	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 (realized)	(4,670)	—	—	(4,670)
Deferred income taxes	10,722	(4,077)	—	6,645
Earnings of affiliates	(14,751)	—	14,751	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	9,172	(6,357)	—	2,815
Joint interest and other receivables	2,286	—	—	2,286
Income taxes	(12,014)	11,979	—	(35)
Prepaid expenses and other assets	(51,920)	(36,588)	91,217	2,709
Asset retirement obligations settlements	(11,936)	(4,406)	—	(16,342)
Accounts payable, accrued liabilities and other	69,230	1,137	(91,217)	(20,850)
Net cash provided by operating activities	99,850	18,640	—	118,490
Investing activities:				
Investment in oil and natural gas properties and equipment	(71,788)	(23,279)	—	(95,067)
Investment in subsidiary	(4,639)	—	4,639	—
Purchases of furniture, fixtures and other	(260)	—	—	(260)
Net cash used in investing activities	(76,687)	(23,279)	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)
Other	(65)	—	—	(65)
Investment from parent	—	4,639	(4,639)	—
Net cash provided (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

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

Condensed Consolidating Statement of Cash Flows for the Three Months Ended March 31, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$26,618	$ 13,100	$ (13,100)	$ 26,618
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	86,416	22,456	—	108,872
Amortization of debt issuance costs and premium	447	—	—	447
Share-based compensation	2,255	—	—	2,255
Derivative loss	3,368	—	—	3,368
Cash payments on derivative settlements (realized)	(4,271)	—	—	(4,271)
Deferred income taxes	11,774	733	—	12,507
Earnings of affiliates	(13,100)	—	13,100	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	172	251	—	423
Joint interest and other receivables	25,875	—	—	25,875
Income taxes	(3,957)	6,329	—	2,372
Prepaid expenses and other assets	4,911	(24,155)	24,155	4,911
Asset retirement obligations settlements	(23,311)	(153)	—	(23,464)
Accounts payable, accrued liabilities and other	34,191	(115)	(24,155)	9,921
Net cash provided by operating activities	151,388	18,446	—	169,834
Investing activities:				
Investment in oil and natural gas properties and equipment	(118,180)	(18,446)	—	(136,626)
Purchases of furniture, fixtures and other	(114)	—	—	(114)
Net cash used in investing activities	(118,294)	(18,446)	—	(136,740)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	112,000	—	—	112,000
Repayments of long-term debt – revolving bank credit facility	(139,000)	—	—	(139,000)
Dividends to shareholders	(6,020)	—	—	(6,020)
Other	(42)	—	—	(42)
Net cash used in financing activities	(33,062)	—	—	(33,062)
Increase in cash and cash equivalents	32	—	—	32
Cash and cash equivalents, beginning of period	12,245	—	—	12,245
Cash and cash equivalents, end of period	$12,277	$ —	$ —	$ 12,277

23

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, 2013 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 approximately 67 producing offshore fields in federal and state waters (62 producing and five fields capable of producing). We currently have under lease approximately 1.2 million gross acres, including approximately 0.6 million gross acres on the Gulf of Mexico Shelf, approximately 0.5 million gross acres in the deepwater and approximately 50,000 gross acres onshore in West 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-owned 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 profitably increasing production and finding oil and gas reserves at a favorable cost. 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 three months ended March 31, 2014 were comprised of 39.7% oil and condensate, 12.0% NGLs and 48.3% natural gas, determined using the energy equivalency ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price per one barrel oil equivalent ("Boe") for oil, NGLs and natural gas may differ significantly. In the three months ended March 31, 2014, revenues from the sale of oil and NGLs made up 74.9% of our total revenues compared to 83.3% in the same period of 2013. For the three months ended March 31, 2014, our combined total production of oil, condensate, NGLs and natural gas was 3.1% lower on a Boe basis than during the same period in 2013, and our total revenues were 1.8%

lower in the three months ended March 31, 2014, driven primarily by lower oil production and lower oil prices, partially offset by higher natural gas prices. See section Results of Operations – Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013 for additional information on our revenues and production.

In November and December 2013, we acquired from Callon certain oil and gas leasehold interests in the Gulf of Mexico. The Callon Properties consist of a 15% working interest in the Medusa field (deepwater Mississippi Canyon blocks 582 and 583), interest in associated production facilities and various interests in other non-operated fields. The operating results of the Callon Properties are included in our results for the three months ended March 31, 2014. The results for the three months ended March 31, 2013 do not include the Callon Properties' operations as this period precedes the acquisition date. See Part I, Item 1, Financial Statements - Note 2 - Acquisitions and Divestitures, for additional information.

The infrastructure to transport crude oil within the United States has seen a major change over the past few years. A number of pipelines have been built and completed, reversed flowed, or expanded to move crude oil from Cushing, Oklahoma (a major crude oil storage hub). Transportation capacity has also been added in major producing regions like the Permian Basin to move crude oil to the U.S. Gulf Coast rather than to Cushing. Both of these events have helped relieve the excess crude oil that built up in Cushing, which in turn allowed WTI pricing to increase relative to Brent up until October 2013. Since that time, the premiums that the Gulf of Mexico crude oil had been experiencing declined as the crude being moved to the U.S. Gulf Coast increased and imports continued. The structural changes that have occurred as a result of new pipeline and rail infrastructure are expected to impact U.S. Gulf Coast crude oil pricing going forward. Rail receiving capacity has also been expanding rapidly on the East Coast and to some extent on the U.S. Gulf Coast. The spread between Brent and WTI continues to be relatively wide due to high U.S. crude oil inventory caused by both crude oil imports and increased domestic production. Spreads are expected to remain volatile and certain U.S. crudes are selling at a discount to WTI due to excess supplies of certain crudes in certain areas of the country.

During the three months ended March 31, 2014, our average realized oil sales price continued at historically high levels, but were 8.0% lower than those realized in the same period of 2013. Two comparable oil price benchmarks are the unweighted average daily posted spot price of WTI crude oil, which increased 4.6% from the comparable period (from $94.33 per barrel to $98.68 per barrel), and the unweighted average daily posted spot price of Brent crude oil, which decreased 3.8% (from $112.47 per barrel to $108.14 per barrel) from the comparable period, as reported from the U.S. Energy Information Administration ("EIA"). 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. Most of our oil production is from offshore Gulf of Mexico, which is comprised of various crudes including Light Louisiana Sweet, Heavy Louisiana Sweet, Poseidon and others. Over the past several years, we had been realizing high premiums on our Gulf Coast crudes, but these premiums decreased significantly during the fourth quarter of 2013. The premiums realized have recovered partially during the first quarter of 2014, but are lower compared to the first quarter of 2013. For example, the premiums for LLS and Heavy Louisiana Sweet for the first quarter of 2014 ranged from $5.00 to $10.00 per barrel above WTI compared to $18.00 to $22.00 per barrel for the first quarter of 2013, which was a major factor in the decrease of our average realized oil sales price in the first quarter of 2014 when compared to the first quarter of 2013. In addition, our average realized prices from our oil production in West Texas incurs discounts for transportation costs incurred by the purchaser, with larger discounts applied where the oil is trucked due to lack of pipeline access.

Oil prices are affected by world events, such as political unrest in the Middle East, the threat of hostilities, demand changes in various countries and world economic growth. Thus, crude oil prices will likely continue to be volatile. For the first quarter of 2014, WTI crude oil prices ranged from $91.00 to $105.00 per barrel and Brent crude oil prices ranged from $106.00 to $111.00 per barrel. The EIA estimates that the average WTI crude spot price was $99.00 per barrel during the first quarter of 2014 and will be $95.00 per barrel in 2014 and $90.00 per barrel in 2015. EIA estimates the average Brent crude oil spot price was $108.00 per barrel during the first quarter of 2014 and projects the average price to be $105.00 in 2014 and $101.00 per barrel in 2015. EIA expects world-wide supply and consumption for oil and liquids fuels to be fairly equal for 2014 and 2015, resulting in minor inventory withdrawals or builds.

Our average realized NGLs sales prices increased 11.7% during the first quarter of 2014 compared to the first quarter of 2013. The two major components of our NGLs are ethane and propane, which typically make up over 70% of a NGL barrel. During the first quarter of 2014, prices for domestic ethane increased 36% and domestic propane prices increased 30% from the comparable 2013 period. Price changes for other domestic NGLs were relatively unchanged. Colder weather was a major factor in the increase of the price of propane. Other market factors influenced the temporary increase in the price of ethane, as it is not used directly as a heating fuel. However, because ethane has been left in the natural gas stream due to the price weakness, the increase in natural gas prices that occurred during the first quarter also led to an increase in ethane prices. Ethane prices have since declined during April 2014. As long as the crude to natural gas price ratio 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 downward price pressure on the price of ethane. Many natural gas processing facilities are re-injecting ethane back into the natural gas stream after processing due to excess ethane supplies. This in turn has increased natural gas supplies and negatively impacted natural gas pricing.

Prices for natural gas in the U.S. improved during the first quarter of 2014 versus the comparable 2013 period largely due to above-average storage withdrawals in response to the colder winter weather in 2014 and higher industrial demand. The amount of heating degree days for the winter was 13% higher than last year, which was a primary causal factor for the increased demand. 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. During the first quarter of 2014, the average realized sales price for our natural gas production increased 48.5% from the comparable 2013 period to $5.02 per Mcf. A comparable benchmark is the Henry Hub unweighted average daily posted spot price, which increased 48.4% from the comparable period.

Although the price of natural gas has increased significantly on a percentage basis, 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 continuing to drill in order to secure and to hold large lease positions before expiration, particularly in shale and similar resource plays, (ii) natural gas continuing to be produced as a by-product in conjunction with the high level of oil drilling, (iii) increasing availability of liquefied natural gas, (iv) production efficiency gains being achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling and production techniques and (v) re-injecting ethane into the natural gas stream as indicated above, which increases the natural gas supply.

Per EIA, natural gas working inventories at the end of the first quarter of 2014 were estimated at 965 billion cubic feet (“Bcf”), which is 44% below the comparable 2013 period. EIA estimates the Henry Hub natural gas spot price was $5.06 per million British thermal unit (“MMBtu”) in the first quarter of 2014 and forecasts $4.44 per MMBtu for 2014 and $4.14 per MMBtu in 2015. Even with the colder winter, EIA projects U.S. supply to be higher than consumption for both 2014 and 2015.

According to Baker Hughes, the U.S. natural gas rig count was 439 at the beginning of 2013. The natural gas rig count decreased during 2013 to 372 rigs at the end of 2013 and decreased further to 316 at the end of March 2014. Despite the decline in rigs drilling specifically for natural gas, the U.S. has experienced a year over year increase in natural gas production due to the many factors previously enumerated. Oil wells have increased natural gas production as a by-product, with the number of rigs searching for oil increasing from 1,318 at the beginning of 2013 to 1,378 at the end of 2013, and further increasing to 1,498 as of the end of March 2014. In the Gulf of Mexico, there were 48 rigs (29 oil, 19 natural gas) at the beginning of 2013, 59 rigs (39 oil, 20 natural gas) at the end of 2013 and 49 rigs (36 oil and 13 natural gas) as of the end of March 2014. EIA estimates the percentage of electricity fueled by natural gas to be 25% in the first quarter of 2014 compared to 26% in the first quarter of 2013, and forecasts the percentage at 27% in 2014 and 28% in 2015, influenced largely by the expected price of natural gas compared to the expected price of coal. Industry sources have indicated that a natural gas price above $4.50 per Mcf for some period of time will probably cause even more power producers to switch back to coal from natural gas, which in effect creates limits to how far natural gas prices can rise until such time as demand for natural gas increases from other sources. The demand for natural gas is expected to continue to increase as the announced petrochemical facilities are constructed and power producers convert to consuming natural gas to reduce emissions or comply with new emission limitations.

Should prices decline for oil, NGLs and natural gas in the future, it would negatively impact our future oil, NGLs and natural gas revenues, earnings and liquidity, and could result in ceiling test write-downs of the carrying value of our oil and natural gas properties, reductions in proved reserves, issues with financial ratio compliance, and a reduction of the borrowing base associated with our Credit Agreement, depending on the severity of such declines. If any of these events were to occur and were significant, it may limit the willingness of financial institutions and investors to provide capital to us and others in the oil and natural gas industry.

As reported and discussed in more detail in Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q, W&T Offshore, Inc., the Parent Company, received a Notice of Suspension and Proposed Debarment and a Notice of Clean Water Act Listing from the EPA. The Notices apply to the Parent Company but are not directed to our wholly-owned subsidiaries. Accordingly, under the current scope of the Notices, the drilling and leasing operations of our wholly-owned subsidiary, Energy VI, have not been materially impacted by the debarment and suspension, nor has the Parent Company's drilling, exploration and production operations on its existing Federal leases.

Also as reported and discussed in more detail in Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q, in late 2013, W&T Offshore, Inc. received letters from the BOEM claiming that W&T Offshore, Inc. no longer qualified for a waiver of certain supplemental bonding for potential offshore decommissioning, plugging and abandonment liabilities. We have transferred a number of assets and related ARO liabilities to one of our wholly-owned subsidiaries, Energy VI, to assist the Parent Company in its efforts to obtain from the BOEM a continuation of the waiver of supplemental bonding requirements for the Parent Company. This has resulted in increased annual bond fees of $0.9 million for our bonded subsidiary. To date, letters of credit have not been required to secure supplemental bonding for Energy VI, but it is possible that letters of credit may be required in the future. The revolving bank credit facility allows for the issuance of up to $300.0 million of letters of credit. If we were required to post letters of credit for this purpose, this would utilize a portion of our borrowing capacity available under our revolving bank credit facility. While this exposure cannot be specifically quantified at this time, we believe our revolving bank credit facility has sufficient letter of credit capacity if needed. We do not believe any reduced borrowing capacity resulting from any future letters of credit, if required to support such supplemental bonding of our subsidiaries, will materially impact our liquidity or substantially limit our future operations.

As described in Part I, Item 1, Financial Statements – Note 1 – Basis of Presentation, of this Form 10-Q, in the fourth quarter of 2013, we identified that we had been receiving an erroneous conversion factor from a third party that had the effect of understating natural gas production in prior periods. The amounts included in the adjustment recognized in the fourth quarter 2013 period which relate to the first quarter of 2013 were: an increase in natural gas production volumes of 264 MMcf (with no corresponding increase in revenue); an increase in DD&A expense of $0.8 million; and a decrease in net income of $0.5 million. The additional volumes would have revised prices to $57.00 per Boe from the reported $57.53 per Boe.

Many changes in laws, regulations, guidance, interpretations and policy continue to be proposed and issued in our industry. The process for obtaining offshore drilling permits, especially deepwater drilling permits, has expanded and lengthened in the past few years. The most significant regulation changes in recent years are regulations related to potential environmental impacts, spill response documentation, compliance reviews, operator practices related to safety and implementing a safety and environmental management system. The new regulations and increased review process increases the time to obtain drilling permits and increases the cost of operations. Also, the regulations have changed related to plugging and abandonment of offshore wells and related infrastructure considerably, driving up both the time and cost to perform the work. As these new regulations and guidance continue to evolve, we cannot estimate the cost and impact to our business at this time.

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,			
	2014[(1)]	2013	Change	%
	(In thousands, except percentages and per share data)			
Financial:				
Revenues:				
Oil	$170,705	$197,564	$(26,859)	(13.6)%
NGLs	20,022	18,327	1,695	9.2 %
Natural gas	63,338	42,937	20,401	47.5 %
Other	451	394	57	14.5 %
Total revenues	254,516	259,222	(4,706)	(1.8)%
Operating costs and expenses:				
Lease operating expenses	55,617	59,341	(3,724)	(6.3)%
Production taxes	1,992	1,789	203	11.3 %
Gathering and transportation	5,296	4,444	852	19.2 %
Depreciation, depletion, amortization and accretion	123,306	108,872	14,434	13.3 %
General and administrative expenses	23,588	21,087	2,501	11.9 %
Derivative loss	7,492	3,368	4,124	122.4%
Total costs and expenses	217,291	198,901	18,390	9.2 %
Operating income	37,225	60,321	(23,096)	(38.3)%
Interest expense, net of amounts capitalized	19,388	18,801	587	3.1 %
Income before income tax expense	17,837	41,520	(23,683)	(57.0)%
Income tax expense	6,648	14,902	(8,254)	(55.4)%
Net income	$11,189	$26,618	$(15,429)	(58.0)%
Basic and diluted earnings per common share	$0.15	$0.35	$(0.20)	(57.1)%

(1) In the fourth quarter of 2013, we acquired the Callon Properties.

	Three Months Ended March 31, 2014(1)	2013	Change	%
Operating:				
Net sales:				
Oil (MBbls)	1,732	1,844	(112)	(6.1)%
NGLs (MBbls)	523	535	(12)	(2.2)%
Natural gas (MMcf)	12,618	12,720	(102)	(0.8)%
Total oil equivalent (MBoe) (2)	4,358	4,499	(141)	(3.1)%
Total natural gas equivalents (MMcfe) (2)	26,150	26,993	(843)	(3.1)%
Average daily equivalent sales (Boe/day) (2)	48,427	49,988	(1,561)	(3.1)%
Average daily equivalent sales (Mcfe/day) (2)	290,560	299,928	(9,368)	(3.1)%
Average realized sales prices:				
Oil ($/Bbl)	$98.56	$107.15	$(8.59)	(8.0)%
NGLs ($/Bbl)	38.26	34.25	4.01	11.7%
Natural gas ($/Mcf)	5.02	3.38	1.64	48.5%
Oil equivalent ($/Boe) (2)	58.29	57.53	0.76	1.3 %
Natural gas equivalent ($/Mcfe) (2)	9.72	9.59	0.13	1.4 %
Average per Boe ($/Boe) (2):				
Lease operating expenses	$12.76	$13.19	$(0.43)	(3.3)%
Gathering and transportation	1.22	0.99	0.23	23.2%
Production costs	13.98	14.18	(0.20)	(1.4)%
Production taxes	0.46	0.40	0.06	15.0%
Depreciation, depletion, amortization and accretion	28.29	24.20	4.09	16.9%
General and administrative expenses	5.41	4.69	0.72	15.4%
	$48.14	$43.47	$4.67	10.7%
Average per Mcfe ($/Mcfe) (2):				
Lease operating expenses	$2.13	$2.20	$(0.07)	(3.2)%
Gathering and transportation	0.20	0.16	0.04	25.0%
Production costs	2.33	2.36	(0.03)	(1.3)%
Production taxes	0.08	0.07	0.01	14.3%
Depreciation, depletion, amortization and accretion	4.72	4.03	0.69	17.1%
General and administrative expenses	0.90	0.78	0.12	15.4%
	$8.03	$7.24	$0.79	10.9%

(1) In the fourth quarter of 2013, we acquired the Callon Properties.

(2) The conversion 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:

Boe - barrel of oil equivalent

Boe/day - barrel of oil equivalent per day

MBbls - thousand barrels for crude oil, condensate or NGLs

MBoe - thousand barrels of oil equivalent

MMcf - million cubic feet

MMcfe - million cubic feet equivalent

Mcfe/day - thousand cubic feet equivalent per day

	Three Months Ended March 31, 2014	2013	Change	%
Total number of wells drilled (gross):				
Offshore	2	2	—	—
Onshore	10	14	(4)	(28.6)%
Total number of productive wells drilled (gross)				
Offshore	2	1	1	100.0%
Onshore	9	14	(5)	(35.7)%

Three Months Ended March 31, 2104 Compared to the Three Months Ended March 31, 2013

Revenues. Total revenues decreased $4.7 million to $254.5 million for the first quarter of 2014 as compared to the same period in 2013. Oil revenues decreased $26.9 million, NGLs revenues increased $1.7 million, natural gas revenues increased $20.4 million and other revenues increased by $0.1 million. The oil revenue decrease was attributable to a 6.1% decrease in sales volumes and an 8.0% decrease in the average realized sales price to $98.56 per barrel for the first quarter of 2014 from $107.15 per barrel for the prior year period. The NGLs revenue increase was attributable to an 11.7% increase in the average realized sales price to $38.26 per barrel for the first quarter of 2014 from $34.25 per barrel for the prior year period and partially offset by a decrease of 2.2% in sales volumes from the comparable period. The increase in natural gas revenue resulted from a 48.5% increase in the average realized natural gas sales price to $5.02 per Mcf in the first quarter of 2014 from $3.38 per Mcf for the prior year period and partially offset by a 0.8% decrease in sales volumes from the comparable period. Production was negatively impacted for all commodities from natural production declines, production deferrals affecting various fields and the divestitures of certain fields in 2013. Conversely, we experienced an increase in production from the new A-5 well at Mississippi Canyon 243 (Matterhorn), the A-14 well at Ship Shoal 349 (Mahogany) and the acquisition of the Callon Properties. The production deferrals were attributable to third-party pipeline outages, platform maintenance, and various operational issues. We estimate production deferrals were 4.0 billion cubic feet equivalent (“Bcfe”) during the first quarter of 2014. Specifically, production at Mississippi Canyon 506 (Wrigley) continues to be deferred as a result of maintenance at Shell’s Cognac platform and comprised approximately 25% of the deferred production. Production from selected wells at Ship Shoal 349 (Mahogany) was deferred due to closure of a pipeline for eight days from high pressure. In addition, weather was a contributing factor for production declines at West Texas and at selected offshore fields. The balance of the deferred production occurred at multiple locations. During the first quarter of 2013, we experienced production deferrals of 1.4 Bcfe primarily at Mississippi Canyon 506 (Wrigley).

Revenues from oil and liquids as a percent of our total revenues were 74.9% for the first quarter of 2014 compared to 83.3% for the comparable 2013 period. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 38.8% for the first quarter of 2014 compared to 32.0% for the comparable 2013 period.

Lease operating expenses. Lease operating expenses, which includes base lease operating expenses, insurance premiums, workovers and maintenance on our facilities, and hurricane related expenses and insurance reimbursements, decreased $3.7 million to $55.6 million in the first quarter of 2014 compared to the prior year period. On a per Boe basis, lease operating expenses decreased to $12.76 per Boe during the first quarter 2014 compared to $13.19 per Boe during the comparable 2013 period. On a component basis, insurance premiums decreased $2.1 million. Hurricane related expenses and insurance reimbursements decreased $0.9 million due to reimbursements received in the first quarter of 2014 and repair expenses incurred in the first quarter of 2013. The other components had lesser net variances, with facilities maintenance decreasing by $0.6 million, base lease operating expenses decreasing by $0.4 million, and workover expense increasing by $0.3 million.

Production taxes. Production taxes increased $0.2 million to $2.0 million in the first quarter of 2014 compared to the prior year period primarily due to onshore activities and are currently not a large component of our operating costs. Most of our production is from federal waters where no production taxes are imposed, whereas onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $0.9 million to $5.3 million for the first quarter of 2014 compared to the prior year period primarily due to escalation in third-party transportation fees.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to $28.29 per Boe for the first quarter of 2014 from $24.20 per Boe in the prior year period. On a nominal basis, DD&A increased to $123.3 million for the first quarter of 2014 from $108.9 million in the prior year period. DD&A on a per Boe basis and nominal basis increased primarily due to increases in estimated future development costs made in the fourth quarter of 2013, and partially due to other increases to the full cost pool without significant changes to proved reserves.

General and administrative expenses. G&A increased to $23.6 million for the first quarter of 2014 from $21.1 million for the prior year period primarily due to increases in surety bond fees, contract labor and professional fees. G&A on a per Boe basis was $5.41 per Boe for the first quarter of 2014, compared to $4.69 per Boe for the prior year period.

Derivative loss. For the first quarter of 2014 and 2013, our derivative positions resulted in net losses of $7.5 million and $3.4 million, respectively, and relate to the change in the fair value of our crude oil commodity derivatives as a result of changes in crude oil prices. Although the contracts relate to production for the entire year, changes in the fair value for all open contracts are recorded currently. For the first quarter of 2014, the net loss was comprised of a $4.7 million realized loss and a $2.8 million unrealized loss. For the first quarter of 2013, the net loss consisted of a realized loss of $4.3 million and an unrealized gain of $0.9 million. For additional information about our derivatives, refer to Part I, Item 1, Financial Statements – Note 4 – Derivative Financial Instruments, of this Form 10-Q.

Interest expense. Interest expense incurred increased to $21.5 million for the first quarter of 2014 from $21.2 million for the prior year period. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both the first quarter of 2014 and 2013. During the first quarter of 2014 and 2013, $2.1 million and $2.4 million, 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 2013.

Income tax expense. Income tax expense was $6.6 million for the first quarter of 2014 compared to $14.9 million for the same period of 2013 with the decrease primarily attributable to lower pre-tax income. 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. Our effective tax rate for the first quarter of 2013 was 35.9% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes.

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 and pay dividends. 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 three months ended March 31, 2014 was $118.5 million compared to $169.8 million for the three months ended March 31, 2013. The change was primarily due to changes in working capital, due primarily to changes in joint interest receivables and accounts payable. Changes in cash flow from operations, excluding changes in working capital, were relatively minor, with lower revenues offset by lower lease operating expenses. Our combined average realized sales price per Boe was 1.3% higher than in the comparable 2013 period due to higher average realized natural gas sales prices. Our combined production of oil, NGLs and natural gas on a Boe basis during the three months ended March 31, 2014 decreased 3.1% from the comparable 2013 period.

Net cash used in investing activities during the three months ended March 31, 2014 and 2013 was $95.3 million and $136.7 million, respectively, which represents our investments in both offshore and onshore oil and gas properties. The decrease is primarily attributable to decreases in both onshore drilling and offshore activity. There were no acquisitions or divestitures of significance completed in either period.

Net cash used in financing activities was $18.6 million and $33.1 million during the three months ended March 31, 2014 and 2013, respectively. The net cash used during the three months ended March 31, 2014 was primarily attributable to net repayments of borrowings on our revolving bank credit facility of $11.0 million and dividend payments of $7.6 million. The net cash used in the three months ended March 31, 2013 was primarily attributable to net repayments of borrowings on our revolving bank credit facility and dividend payments.

At March 31, 2014, we had a cash balance of $20.3 million and $520.6 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $800.0 million as of March 31, 2014. Effective April 17, 2014, our borrowing base was changed to $750.0 million upon completion of the semi-annual redetermination by our lenders and on that date, the undrawn capacity was $455.6 million. The undrawn capacity fluctuates based on borrowings and repayments, which can occur on a daily basis.

Credit Agreement and long-term debt. At March 31, 2014 and December 31, 2013, $279.0 million and $290.0 million, respectively, were outstanding under our revolving bank credit facility. During the three months ended March 31, 2014, the outstanding borrowings on our revolving bank credit facility ranged from $279.0 million to $323.0 million. At March 31, 2014 and December 31, 2013, $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. For additional information about our long-term debt, refer to Part I, Item 1, Financial Statements – Note 5 – Long-Term Debt, of this Form 10-Q.

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, including a minimum current ratio and a maximum leverage ratio, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement and all applicable covenants related to the 8.50% Senior Notes as of March 31, 2014.

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, 2014, our derivative instruments outstanding consisted of oil contracts relating to approximately 2.8 million barrels (“MMBbls”) of our anticipated production for the balance of 2014. See Part I, Item 1, Financial Statements – Note 4 – Derivative Financial Instruments, of this Form 10-Q for additional information.

Insurance Claims and Insurance Coverage. During 2008, Hurricane Ike caused substantial property damage. Substantially all the costs related to Hurricane Ike have been incurred and we submitted claims under our insurance policies effective at that time, of which $149.6 million has been collected through March 31, 2014. We currently are in dispute with the underwriters of our Excess Policies related to the coverage of removal-of-wreck costs incurred due to Hurricane Ike. The amount in dispute is approximately $46.0 million. Removal-of-wreck costs are recorded in Oil and natural gas properties and equipment on the Balance Sheets. See Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q for additional information.

We currently carry multiple layers of insurance coverage in our Energy Package covering our operating activities, with higher limits of coverage for higher valued properties and wells. The current policy limits for well control range from $30.0 million to $500.0 million depending on the risk profile and contractual requirements. We 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. The well control, named windstorm and physical damage coverage is effective until June 1, 2014. 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 25% 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.

We estimate that a substantial majority of our estimated future net revenues attributable to our Gulf of Mexico properties are covered under our current insurance policies for named windstorm damage. There are certain other properties we have decided not to cover for named windstorm damage as part of our risk assessment process.

Our general and excess liability policies, which were renewed and are effective until May 1, 2015, provide for $300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility requirement under the Oil Pollution Act of 1990, we are required to evidence $150.0 million of financial responsibility to the Bureau of Safety and Environmental Enforcement ("BSEE"). We qualify to self-insure for $54.0 million of this amount and the remaining $96.0 million is covered by insurance.

Although we have not been informed otherwise, 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.

See Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q for information related to notifications from the BOEM concerning supplemental bonding requirements

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,	
	2014	2013
	(In thousands)	
Acquisition of Callon Properties (1)	$(169)	$—
Exploration (2)	51,427	60,624
Development (2)	30,796	73,722
Seismic, capitalized interest, other leasehold costs interest, other leasehold costs	13,013	2,280
Acquisitions and investments in oil and gas property/equipment	$95,067	$136,626

(1) The amount in 2014 represents reductions to the purchase price for post-effective date adjustments.
(2) Reported geographically in the subsequent table.

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

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Conventional shelf	$18,625	$42,220
Deepwater	13,120	21,086
Deep shelf	21,968	21,237
Onshore	28,510	49,803

Exploration and development capital expenditures	$82,223	$134,346

Our capital expenditures for the three months ended March 31, 2014 and 2013 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,			
	2014		2013	
	Gross	Net	Gross	Net
Development wells:				
Offshore wells:				
Productive	—	—	1	1.0
Non-productive	—	—	—	—
Onshore wells:				
Productive	4	4.0	11	11.0
Non-productive	—	—	—	—
Total development wells	4	4.0	12	12.0
Exploration wells:				
Offshore wells:				
Productive	2	1.2	—	—
Non-productive	—	—	1	1.0
Onshore wells:				
Productive	5	5.0	3	2.9
Non-productive	1	1.0	—	—
Total exploration wells	8	7.2	4	3.9
Total wells	12	11.2	16	15.9

Exploration activities. Completion operations on the Mississippi Canyon 698 (Big Bend) well were finalized during the first quarter of 2014, with production dependent on connection to a host platform. The Mississippi Canyon 243 (Matterhorn) A-5 side-track well was brought online during the quarter and averaged over 1,000 Boe per day net during the quarter since coming online.

Acquisitions and funding. We intend to continue to pursue acquisitions and joint venture opportunities during 2014 and beyond should we identify attractive opportunities. For example, in the fourth quarter of 2013, we completed the acquisition of the Callon Properties as described in Part I, Item 1, Financial Statements – Note 2 – Acquisitions and Divestitures, of 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, 2014, in East Texas at our Star Project, we have reassigned approximately 160,000 gross acres back to the original assignor. During the three months ended March 31, 2014, we did not have any divestitures. During 2013, we sold our interests in various fields. See Part I, Item 1, Financial Statements – Note 2 – Acquisitions and Divestitures, of this Form 10-Q for additional information.

Capital Expenditure Budget for 2014. Our total capital expenditure budget for 2014 currently is $450.0 million, not including any potential acquisitions. The budget includes 42% for exploration, 52% for development and 6% for other items. Geographically, the budget is split 68% for offshore and 32% for onshore. During the three months ended March 31, 2014, we did not close on any significant acquisitions. We will continue to evaluate and bid on opportunities as they arise. We anticipate funding our 2014 capital budget, any potential acquisitions and other expenditures with cash flow from operating activities, cash on hand, borrowings under our revolving bank credit facility, divestitures and by accessing the capital markets to the extent necessary. For the portion of our capital budget related to drilling, our operating policy has been to fund these expenditures with cash flow provided by operations. Our 2014 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, 2014 and 2013, we made no income tax payments and did not receive any refunds. For the remainder of 2014, we expect a substantial amount of our income tax will be deferred and expect payments, if any, to be primarily related to alternative minimum tax. We have $263.4 million of net operating loss carryforward (tax basis) available to offset future federal taxable income in 2014 and forward. We also have $12.1 million of alternative minimum tax credit carryforwards available to be utilized in 2014 and forward.

Dividends. See Part I, Item 1, Financial Statements – Note 10 – Dividends, of this Form 10-Q.

Contractual obligations. Updated information on certain contractual obligations is provided in Part I, Item 1, Financial Statements – Note 3 – Asset Retirement Obligations and Note 5 – Long-Term Debt, of this Form 10-Q. As of March 31, 2014, drilling rig commitments were approximately $21.9 million compared to $21.5 million as of December 31, 2013. The current drilling rig commitments expire within one year from March 31, 2014. Except for scheduled utilization, other contractual obligations as of March 31, 2014 did not change materially from the disclosures in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, of our Annual Report on Form 10-K for the year ended December 31, 2013.

Critical Accounting Policies

Our significant accounting policies are summarized in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2013. Also refer to Part 1, Item 1, Financial Statements – Note 1 – Basis of Presentation, of this Form 10-Q.

Recent Accounting Pronouncements

None.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the three months ended March 31, 2014 did not change materially from the disclosures in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, of our Annual Report on Form 10-K for the year ended December 31, 2013. 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, 2013.

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 and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. We currently have open crude oil derivative contracts to manage a portion of our exposure to commodity price risk from sales of oil for the balance of 2014. As of March 31, 2014, these derivative contracts had a notional quantity of 2.8 MMBbls. We do not designate our commodity derivatives as hedging instruments. While these contracts are intended to reduce the effects of volatile oil prices, they may also limit future income from favorable price movements. See Part I, Item 1, Financial Statements – Note 4 – Derivative Financial Instruments, of this Form 10-Q for additional information.

Interest Rate Risk. As of March 31, 2014, we had $279.0 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 1.75% to 2.75% depending on the amount outstanding. We currently do not have any derivative instruments related to interest rates.

Item 4. Controls and Procedures

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

As required by Exchange Act Rule 13a-15(b), we performed an evaluation, under the supervision and with the participation of our management, including our CEO and CFO, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, our CEO and CFO have each concluded that as of March 31, 2014 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, 2014, 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, 2013, 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. 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, 2013.

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, 2014.

W&T OFFSHORE, INC.
By: /s/ JOHN D. GIBBONS
John D. Gibbons
Senior Vice President, Chief Financial Officer and Chief

Accounting 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))
10.1*@	Form of 2014 Executive Annual Incentive Award.
10.2*@	Form of 2014 RSU Executive Award.
10.3*@	Tracy W. Krohn 2014 Annual Award.
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.
@ Compensation agreement
** Furnished herewith.