W&T OFFSHORE INC
Form 10-Q
August 08, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-Q

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

For the quarterly period ended June 30, 2013

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	72-1121985

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

(713) 626-8525

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

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

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

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

As of August 6, 2013, there were 75,277,080 shares outstanding of the registrant s common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2013	December 31, 2012
	(In thousands, except share data)	
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 9,276	$ 12,245
Receivables:		
Oil and natural gas sales	80,670	97,733
Joint interest and other	22,921	56,439
Income taxes	39,556	47,884
Total receivables	143,147	202,056
Deferred income taxes current		267
Prepaid expenses and other assets	37,214	25,555
Total current assets	189,637	240,123
Property and equipment at cost:		
Oil and natural gas properties and equipment (full cost method, of which $127,918 at June 30, 2013 and $123,503 at December 31, 2012 were excluded from amortization)	7,009,835	6,694,510
Furniture, fixtures and other	20,848	21,786
Total property and equipment	7,030,683	6,716,296
Less accumulated depreciation, depletion and amortization	4,851,973	4,655,841
Net property and equipment	2,178,710	2,060,455
Restricted deposits for asset retirement obligations	33,469	28,466
Other assets	18,198	19,943
Total assets	$ 2,420,014	$ 2,348,987
Liabilities and Shareholders Equity		
Current liabilities:		
Accounts payable	$ 123,070	$ 123,885
Undistributed oil and natural gas proceeds	42,068	37,073
Asset retirement obligations	74,687	92,630
Accrued liabilities	13,984	21,021
Deferred income tax current	5,760	
Total current liabilities	259,569	274,609
Long-term debt	1,099,537	1,087,611
Asset retirement obligations, less current portion	309,918	291,423
Deferred income taxes	162,948	145,249

Other liabilities	5,864	8,908
Commitments and contingencies		
Shareholders equity:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at June 30, 2013 and December 31, 2012		
Common stock, $0.00001 par value; 118,330,000 shares authorized; 78,146,253 issued and 75,277,080 outstanding at June 30, 2013, and 78,118,803 issued and 75,249,630 outstanding at December 31, 2012	1	1
Additional paid-in capital	401,097	396,186
Retained earnings	205,247	169,167
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders equity	582,178	541,187
Total liabilities and shareholders equity	$ 2,420,014	$ 2,348,987

See Notes to Condensed Consolidated Financial Statements.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands, except per share data) (Unaudited)			
Revenues	$ 235,383	$ 215,513	$ 494,605	$ 451,399
Operating costs and expenses:				
Lease operating expenses	68,248	60,276	127,590	116,938
Production taxes	1,780	1,335	3,569	2,821
Gathering and transportation	4,608	4,110	9,052	8,330
Depreciation, depletion, amortization and accretion	99,896	85,941	208,767	174,432
General and administrative expenses	19,868	14,623	40,955	44,102
Derivative gain	(12,840)	(49,872)	(9,473)	(10,238)
Total costs and expenses	181,560	116,413	380,460	336,385
Operating income	53,823	99,100	114,145	115,014
Interest expense:				
Incurred	21,536	14,706	42,770	28,612
Capitalized	(2,532)	(3,326)	(4,964)	(6,517)
Income before income tax expense	34,819	87,720	76,339	92,919
Income tax expense	12,423	34,153	27,325	36,134
Net income	$ 22,396	$ 53,567	$ 49,014	$ 56,785
Basic and diluted earnings per common share	$ 0.29	$ 0.70	$ 0.64	$ 0.75
Dividends declared per common share	$ 0.09	$ 0.08	$ 0.17	$ 0.16

See Notes to Condensed Consolidated Financial Statements.

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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, 2012	75,250	$ 1	$ 396,186	$ 169,167	2,869	$ (24,167)	$ 541,187
Cash dividends				(12,795)			(12,795)
Share-based compensation			4,950				4,950
Other	27		(39)	(139)			(178)
Net income				49,014			49,014
Balances at June 30, 2013	75,277	$ 1	$ 401,097	$ 205,247	2,869	$ (24,167)	$ 582,178

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(In thousands) (Unaudited)	
Operating activities:		
Net income	$ 49,014	$ 56,785
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	208,767	174,432
Amortization of debt issuance costs and premium	910	1,287
Share-based compensation	4,950	5,818
Derivative gain	(9,473)	(10,238)
Cash payments on derivative settlements	(2,310)	(6,084)
Deferred income taxes	23,726	48,120
Changes in operating assets and liabilities:		
Oil and natural gas receivables	17,063	26,121
Joint interest and other receivables	33,620	3,630
Insurance receivables	5,015	500
Income taxes	8,579	(22,062)
Prepaid expenses and other assets	(12,381)	(14,110)
Asset retirement obligation settlements	(32,886)	(29,228)
Accounts payable, accrued liabilities and other	2,768	6,354
Net cash provided by operating activities	297,362	241,325
Investing activities:		
Investment in oil and natural gas properties and equipment	(299,213)	(187,284)
Proceeds from sales of oil and natural gas properties and equipment		30,453
Change in restricted cash		(30,763)
Purchases of furniture, fixtures and other	(981)	(668)
Net cash used in investing activities	(300,194)	(188,262)
Financing activities:		
Borrowings of long-term debt revolving bank credit facility	252,000	197,000
Repayments of long-term debt revolving bank credit facility	(239,000)	(234,000)
Dividends to shareholders	(12,795)	(11,898)
Other	(342)	(124)
Net cash used in financing activities	(137)	(49,022)
Increase (decrease) in cash and cash equivalents	(2,969)	4,041
Cash and cash equivalents, beginning of period	12,245	4,512
Cash and cash equivalents, end of period	$ 9,276	$ 8,553

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.

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, 2012.

Reclassifications. Certain reclassifications have been made to the prior periods financial statements to conform to the current presentation. Income taxes was combined with Accrued liabilities on the Balance Sheet and changes in Other liabilities was combined with the changes in Accounts payable and accrued liabilities on the Statement of Cash Flows.

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

Recent Accounting Developments. In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities which applies to certain items in the statement of financial position (balance sheet), and was further clarified in January 2013 by ASU 2013-01, Balance Sheet (Topic 210):Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which clarified the scope of ASU 2011-11 to derivative instruments, repurchase agreements and securities lending transactions. The effective date for the amendments is for annual periods beginning after January 1, 2013, and interim periods within those annual periods. ASU 2011-11 requires disclosures of the gross and net amounts for items eligible for offset in the balance sheet. Although the Company s derivative financial instruments are subject to master netting agreements, the Company records its derivative financial instruments on a gross basis by contract; therefore, the ASUs did not significantly affect the Company s disclosures. Other items of the ASUs were not applicable to the Company.

In February 2013, the FASB issued ASU 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date, which requires an entity that is joint and severally liable to measure the obligation as the sum of the amount the entity has agreed with co-obligors to pay and any additional amount it expects to pay on behalf of one or more co-obligors. Required disclosures include a description of the nature of the arrangement, how the liability arose, the relationship with co-obligors and the terms and conditions of the arrangement. The effective date for the amendment is for annual periods beginning after December 15, 2013, and interim periods within those annual periods. The amendment is to be applied retrospectively to all prior periods presented. The Company is currently assessing the impact of ASU 2013-04 to determine the effects on the balance sheet and disclosures, if any.

2. Acquisitions and Divestitures

2012 Acquisition. On October 5, 2012, we acquired from Newfield Exploration Company and its subsidiary, Newfield Exploration Gulf Coast LLC (together, Newfield) certain oil and gas leasehold interests in the Gulf of Mexico (the Newfield Properties). The Newfield Properties consist of leases covering 78 offshore blocks on approximately 416,000 gross acres (268,000 net acres) (excluding overriding royalty interests), comprised of 65 blocks in the deepwater, six of which are producing, 10 blocks on the conventional shelf, four of which are producing, and an overriding royalty interest in three deepwater blocks, two of which are producing. Including adjustments from an effective date of July 1, 2012, the adjusted purchase price was $205.7 million and we assumed the future asset retirement obligations (ARO) associated with the Newfield Properties. The purchase price was finalized during the second quarter of 2013 and no further adjustments are expected. Adjustments to the purchase price of a net increase of $0.2 million were recorded in the six months ended June 30, 2013. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand. Subsequently in the same month, the amounts borrowed under our revolving bank credit facility were paid down with funds provided from the issuance of long-term debt in October 2012. See Note 6 for information on long-term debt.

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

Oil and natural gas properties and equipment	$ 237,396
Asset retirement obligations current	(7,250)
Asset retirement obligations non-current	(24,414)
Total cash paid	$ 205,732

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 for the Newfield Properties acquisition.

Revenue, Net Income and Pro Forma Financial Information Unaudited

The Newfield Properties were not included in our consolidated results until the closing date of October 5, 2012. For the three months ended June 30, 2013, the Newfield Properties accounted for $33.7 million of revenue, $7.6 million of direct operating expenses, $15.8 million of depreciation, depletion, amortization and accretion (DD&A) and $3.6 million of income taxes, resulting in $6.7 million of net income. For the six months ended June 30, 2013, the Newfield Properties accounted for $62.3 million of revenue, $14.1 million of direct operating expenses, $26.4 million of DD&A and $7.6 million of income taxes, resulting in $14.2 million of net income. The net income attributable to these properties does not reflect certain expenses, such as general and administrative (G&A) expense 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 Newfield 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 Newfield Properties for the three and six months ended June 30, 2012.

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, 2012, the unaudited pro forma financial information was computed as if the acquisition of the Newfield Properties had been completed on January 1, 2011. The financial information was derived from W&T s audited historical consolidated financial statement for annual periods, W&T s unaudited historical condensed consolidated financial statement for the interim periods, the Newfield Properties audited historical financial statement for 2011 and the Newfield Properties unaudited historical financial statements for the 2012 interim periods.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Newfield Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2011. 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 Newfield;

realized sales prices for oil, natural gas liquids (NGLs) and natural gas may have been different; and costs of operating the Newfield Properties may have been different.

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

	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Revenue	$244,987	$524,094
Net income	51,226	59,387
Basic and diluted earnings per common share	0.67	0.78

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 Newfield Properties (in thousands):

	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Revenue (a)	$ 29,474	$ 72,695
Direct operating expense (a)	12,771	24,063
Insurance costs (b)	157	316
DD&A (c)	16,429	36,877
Interest expense (d)	3,960	7,921
Capitalized interest (e)	241	485
Income tax expense (benefit) (f)	(1,261)	1,401

The sources of information and significant assumptions are described below:

(a) Revenues and direct operating expenses for the Newfield Properties were derived from the historical financial records of Newfield.

(b) Incremental costs for insurance were estimated using the incremental costs to add the Newfield Properties to W&T s insurance programs. The direct operating expenses for the Newfield Properties described above excluded insurance costs.

(c) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Newfield Properties costs, reserves and production into our currently existing full cost pool in order to compute such amounts. The purchase price allocation included $13.1 million that was allocated to the pool of unevaluated properties for oil and natural gas interests. Accordingly, no DD&A expense was estimated for the unevaluated properties. ARO was estimated by W&T management.

(d) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $205.7 million, which equates to the cash paid including purchase price adjustments and an interest rate of 7.7%, which equates to the effective yield on net proceeds for the additional senior notes issued shortly after the acquisition closed.

(e) Incremental capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings.

(f) Income tax expense was computed using the 35% federal statutory rate.

2012 Divestiture. On May 15, 2012, we sold our 40%, non-operated working interest in the South Timbalier 41 field located in the Gulf of Mexico for $30.5 million with an effective date of April 1, 2012. 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 could be executed. Replacement purchases were consummated during 2012. In connection with this sale, we reversed $4.0 million of ARO.

3. Hurricane Remediation and Insurance Claims

During the third quarter of 2008, Hurricane Ike caused substantial damage to certain of our properties and we continue to incur costs and submit claims to our insurance underwriters related to repairing such damage. Our insurance policies in effect on the occurrence date of Hurricane Ike had a retention requirement of $10.0 million per occurrence, which has been satisfied, and coverage policy limits of $150.0 million for property damage due to named windstorms (excluding damage at certain facilities) and $250.0 million for, among other things, removal of wreckage if mandated by any governmental authority.

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection, which arises when our insurance underwriters adjuster reviews and approves such costs for payment by the underwriters. Claims that have been processed in this manner have customarily been paid on a timely basis.

From the third quarter of 2008 through June 30, 2013, we have received $147.2 million from our insurance underwriters related to Hurricane Ike. To the extent that additional remediation costs or plug and abandonment costs are incurred that are not covered by insurance, we expect that our available cash and cash equivalents, cash flow from operations and the availability under our revolving bank credit facility will be sufficient to meet necessary expenditures that may exceed our insurance coverage for damages incurred as a result of Hurricane Ike. See Note 4 for additional information about the impact of hurricane related items on our ARO. See Note 12 for information regarding legal actions taken by certain insurers and the Company.

4. Asset Retirement Obligations

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

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

Balance, December 31, 2012	$384,053
Liabilities settled	(32,886)
Accretion of discount	10,924
Liabilities incurred	372
Revisions of estimated liabilities due to Hurricane Ike	4,160

Revisions of estimated liabilities all other (1)	17,982
Balance, June 30, 2013	384,605
Less current portion	74,687
Long-term	$309,918

(1) Revisions are primarily due to increases in the scope of work at several offshore locations required by the Bureau of Safety and Environmental Enforcement.

5. 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 oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. Our derivative financial instruments currently consist of crude oil swap contracts. 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. 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. For additional information about fair value measurements, refer to Note 7.

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 six months ended June 30, 2013 and 2012, our derivative contracts consisted entirely of crude oil contracts. The crude oil swap contracts are comprised of a portion based on Brent crude oil prices and a portion based on West Texas Intermediate (WTI) crude oil prices. The Brent based swaps are priced off the Brent crude oil price quoted on the IntercontinentalExchange, known as ICE. The WTI based swaps are priced off the New York Mercantile Exchange, known as NYMEX. 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 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.

As of June 30, 2013, our open commodity derivatives contracts were as follows:

	Swaps Oil			
	Priced off Brent (ICE)		Priced off WTI (NYMEX)	
Termination Period	Notional Quantity (Bbls)	Weighted Average Contract Price	Notional Quantity (Bbls)	Weighted Average Contract Price
2013: 3rd quarter	405,800	$ 103.85	185,000	$ 97.13
4th quarter	294,400	101.98	520,000	97.38
2014: 1st quarter	180,000	97.38	59,000	97.02
2nd quarter	172,900	97.38		
3rd quarter	165,600	97.38		
4th quarter	156,400	97.37		
	1,375,100	$ 100.27	764,000	$ 97.29

Bbls = barrels

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

	June 30, 2013	December 31, 2012
Prepaid and other assets	$ 2,635	$
Other Assets (noncurrent)	221	
Accrued liabilities	475	6,355
Other liabilities (noncurrent)		3,046

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Derivative (gain) loss:				
Realized	$ (1,961)	$ 285	$ 2,310	$ 6,084
Unrealized	(10,879)	(50,157)	(11,783)	(16,322)
Total	$ (12,840)	$ (49,872)	$ (9,473)	$ (10,238)

Offsetting Commodity Derivatives. As of June 30, 2013 and December 31, 2012, 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 presents disclosures required by ASU 2011-11 and ASU 2013-01 and 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 as of June 30, 2013.

	Derivative Assets	Derivative Liabilities
Gross amounts presented in the balance sheet	$ 2,856	$ 475
Amounts not offset in the balance sheet	(348)	(348)
Net amounts	$ 2,508	$ 127

There were no potential effects of master netting agreements on the fair value of open derivative contracts as of December 31, 2012 due to all open derivative contracts being valued as liabilities.

6. Long-Term Debt

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

	June 30, 2013	December 31, 2012
8.50% Senior Notes	$ 900,000	$ 900,000
Debt premiums, net of amortization	16,537	17,611
Revolving bank credit facility	183,000	170,000
Total long-term debt	1,099,537	1,087,611
Current maturities of long-term debt		
Long-term debt, less current maturities	$ 1,099,537	$ 1,087,611

At June 30, 2013 and December 31, 2012, 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 June 30, 2013.

The Fourth Amended and Restated Credit Agreement (the Credit Agreement) governs our revolving bank credit facility and terminates on May 5, 2015. 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 June 30, 2013 and December 31, 2012, we had $0.1 million of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 4.1% for the six months ended June 30, 2013 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 June 30, 2013, our borrowing base was $800.0 million and our borrowing availability was $616.9 million.

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 June 30, 2013.

For information about fair value measurements for our 8.50% Senior Notes and revolving bank credit facility, refer to Note 7.

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

7. 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 for the periods indicated (in thousands).

		June 30, 2013		December 31, 2012	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$ 2,856	$ 475	$	$ 9,401
8.50% Senior Notes	Level 2		936,000		963,000
Revolving bank credit facility	Level 2		183,000		170,000

As described in Note 5, 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 6.

8. 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 on May 7, 2013. As allowed by the Plan, in 2013, 2012 and in 2011, 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. Certain RSUs granted in 2013 (the 2013 RSUs) are subject to performance criteria of Adjusted EBITDA, defined as net income before income tax expense, net interest expense, depreciation, depletion, amortization, accretion and certain other items, adjusted EBITDA as a percent of total revenue (Adjusted EBITDA Margin) and total shareholder return (TSR). The RSUs granted in 2012 (the 2012 RSUs) are subject to performance criteria of earnings per share and TSR, while the RSUs granted in 2011 (the 2011 RSUs) are subject to only earnings per share performance measurement. In 2013 and in prior years, restricted stock was granted to the Company s non-employee directors under the Director Compensation Plan. The restricted stock and RSUs each vest at the end of specified service periods. 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 predetermined performance criteria.

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.

On May 7, 2013, after receiving shareholder approval, 4,000,000 shares of common stock were added to the amount available for issuance under the Plan. At June 30, 2013, there were 5,393,602 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 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.

Restricted Stock. As of June 30, 2013, all of the unvested 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 shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. The fair value of restricted stock was estimated by using the Company s closing price on the grant date.

A summary of activity related to restricted stock is as follows:

	Restricted Stock		
	Shares		Weighted Average Grant Date Fair Value Per Share
Outstanding restricted shares, December 31, 2012	43,687	$	18.69
Granted	27,450		12.75
Vested	(27,297)		17.09
Outstanding restricted shares, June 30, 2013	43,840	$	15.96

Subject to the satisfaction of service conditions, the outstanding restricted shares issued to the non-employee directors as of June 30, 2013 are expected to vest as follows:

	Shares
2014	19,445
2015	15,245
2016	9,150
Total	43,840

The grant date fair value of restricted shares granted during the six months ended June 30, 2013 and 2012 was $0.3 million and $0.4 million, respectively. The fair value of restricted shares that vested during the six months ended June 30, 2013 and 2012 was $0.4 million and $0.5 million, respectively.

Restricted Stock Units. As of June 30, 2013, the Company had outstanding RSUs issued to certain employees. Certain 2013 RSUs are subject to pre-defined share performance measures comprised of Adjusted EBITDA and Adjusted EBITDA Margin for 2013 and TSR for defined periods in 2013, 2014 and 2015; therefore, no portion has been determined to be eligible for vesting as of June 30, 2013. A portion of the 2012 RSUs remains subject to the certain pre-defined performance measures of TSR for the defined periods in 2013 and 2014; therefore, this portion will be determined whether eligible for vesting at the end of the respective performance periods. TSR is determined based upon the change in the entity s stock price and dividends for the performance period. The TSR targets are the ranking of the Company s TSR compared to the TSR of certain peer companies. The TSR components have an issuance scale from 0% to 200%. The portion of RSUs subject to TSR performance measurement is disclosed in the second table below.

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. The fair value of the 2011 RSUs, which contained only Company-specific performance measures, was estimated by using the Company s closing price on the grant date.

The majority of RSUs are subject to predetermined performance criteria and all RSUs are subject to service requirements prior to vesting. All RSUs awarded are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed

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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 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding RSUs, December 31, 2012	969,820	$ 22.70
Granted	964,780	13.22
Forfeited	(18,681)	19.36
Outstanding RSUs, June 30, 2013	1,915,919	$ 17.96

Subject to the satisfaction of service conditions, the RSUs outstanding as of June 30, 2013 are eligible to vest in the year indicated in the table below:

		Shares
2013	subject to service requirements	474,044
2014	subject to service requirements	339,033
2014	subject to service and other requirements (1)	139,233
2015	subject to service requirements	23,500
2015	subject to service and other requirements (2)	658,076
2015	subject to service and other requirements (3)	282,033
Total		1,915,919

(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 certain Company-specific performance requirements not yet measureable, with awards ranging from 0% to 150% of amounts granted.

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

The grant date fair value of RSUs granted during the six months ended June 30, 2013 and 2012 was $12.8 million and $14.1 million, respectively. During the six months ended June 30, 2013 and 2012, there was no vesting of RSUs.

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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Share-based compensation expense from:				
Restricted stock	$ 99	$ 108	$ 198	$ 214
Restricted stock units	2,596	3,051	4,752	5,604
Total	$ 2,695	$ 3,159	$ 4,950	$ 5,818
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$ 943	$ 1,106	$ 1,733	$ 2,036

Unrecognized Share-Based Compensation. As of June 30, 2013, unrecognized share-based compensation expense related to our outstanding restricted shares and RSUs was $0.7 million and $19.2 million, respectively. Unrecognized share-based compensation expense will be recognized through April 2016 for restricted shares and November 2015 for RSUs.

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Cash-Based Incentive Compensation. As defined by the Plan, annual incentive awards may be granted to eligible employees payable in cash. 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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Share-based compensation expense included in:				
General and administrative charge to operating income	$ 2,695	$ 3,159	$ 4,950	$ 5,818
Cash-based incentive compensation included in:				
Lease operating expense	747		2,140	1,900
General and administrative	2,024		5,554	1,878
Total charged to operating income	2,771		7,694	3,778
Total incentive compensation charged to operating income	$ 5,466	$ 3,159	$ 12,644	$ 9,596

9. Income Taxes

Income tax expense of $12.4 million and $27.3 million was recorded during the three and six months ended June 30, 2013, respectively. Our effective tax rate for the three and six months ended June 30, 2013 was 35.7% and 35.8%, respectively, and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes. Income tax expense of $34.2 million and $36.1 million was recorded during the three and six months ended June 30, 2012, respectively. Our effective tax rate for the three and six months ended June 30, 2012 was 38.9% for both periods, and differed from the federal statutory rate primarily as a result of the recapture of deductions for qualified domestic production activities under Section 199 of the IRC as a function of loss carrybacks to prior years. Income taxes receivables as of June 30, 2013 are comprised of $44.7 million of refunds related to tax loss carrybacks to 2010 and 2011, which are partially offset by $5.1 million of accrued taxes payable related to 2013 alternative minimum tax.

As of June 30, 2013 and December 31, 2012, we did not have any unrecognized tax benefit recorded. As of June 30, 2013 and December 31, 2012, 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 2009 through 2012 remain open to examination by the tax jurisdictions to which we are subject.

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10. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$ 22,396	$ 53,567	$ 49,014	$ 56,785
Less portion allocated to nonvested shares	275	1,185	556	1,214
Net income allocated to common shares	$ 22,121	$ 52,382	$ 48,458	$ 55,571
Weighted average common shares outstanding	75,223	74,318	75,215	74,309
Basic and diluted earnings per common share	$ 0.29	$ 0.70	$ 0.64	$ 0.75
Shares excluded due to being anti-dilutive (weighted-average)	859	1,913	864	1,839

11. Dividends

During the six months ended June 30, 2013 and 2012, we paid regular cash dividends per common share of $0.17 and $0.16, respectively. On August 7, 2013, our board of directors declared a cash dividend of $0.09 per common share, payable on September 12, 2013 to shareholders of record on August 22, 2013.

12. Contingencies

Cameron Parish Louisiana Claim. Since 2009, certain Cameron Parish landowners have filed suits in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and its Chief Executive Officer, Tracy W. Krohn, as well as several other defendants unrelated to us. In their lawsuits, plaintiffs alleged that property they own has been contaminated or otherwise damaged by the defendants oil and gas exploration and production activities and they are seeking compensatory and punitive damages. During 2012 and for the six months ended June 30, 2013, we settled claims with certain landowners and paid $11.3 million.

Qui Tam Litigation. On September 21, 2012, the Company was served with a complaint in a qui tam action filed under the federal False Claims Act by an employee of a Company contractor. The lawsuit, United States ex rel. Comeaux v. W&T Offshore, Inc., et al.; CA No. 10-494, was filed in the United States District Court for the Eastern

District of Louisiana, against the Company and three other working interest owners related to claims associated with three of the Company s operated production platforms. A qui tam action, also known as a whistleblower action, is a lawsuit brought by a private citizen seeking civil penalties or damages against a person or company on behalf of the government for alleged violations of law. If the claims are successful, the person filing the suit may recover a percentage of the damages or penalty from the lawsuit as a reward for exposing a wrongdoing and recovering funds on behalf of the government. The complaint was originally filed in 2010 but kept under confidential seal in order for the federal government to decide if it wished to intervene and take over the prosecution of the qui tam action. The government declined to intervene in this suit and the complaint was unsealed and made public in June 2012, thereby giving the plaintiff the opportunity to pursue the claims on behalf of the government. The plaintiff is pursuing the claim.

The complaint alleges that environmental violations at three of the Company s operated production platforms in the Gulf of Mexico violate the federal offshore lease provisions so that the Company, among other things, wrongfully retained benefits under the applicable leases. The alleged environmental violations include allegations of discharges of relatively small amounts of oil into the Gulf of Mexico, the failure to report and record such discharges, and falsification of certain produced water samples and related reports required under federal law. The events are alleged to have occurred in 2009. These are largely the same underlying environmental allegations that resulted in the plea agreement described in the audited financial statements included in the Company s Annual Report on Form 10-K for the year ended December 31, 2012. The Company has filed a motion to dismiss the plaintiff s claims. The plaintiff dismissed his claims against the three other working interest owners after they filed motions to dismiss. The plaintiff conceded that certain of his claims should be dismissed in his reply to the Company s motion to dismiss. By order dated August 6, 2013, the court granted the Company s motion to dismiss plaintiff s claims without prejudice and allowed plaintiff twenty days to amend his complaint to remedy the deficiencies in his claims. The court will dismiss with prejudice if the plaintiff cannot or does not correct the deficiencies in his claims.

The Company intends to vigorously defend the claims made in this lawsuit. While the Company has determined that the likelihood of an adverse outcome may be reasonably possible, the range of potential loss cannot yet be estimated, and accordingly, no accrual has been made.

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 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) with only removal of wreck and debris claims. The court consolidated the various suits filed by the underwriters. W&T has not yet filed any claim under such Excess Policies. As of June 30, 2013, we have spent $44.5 million and expect to incur an additional $2.6 million of costs for removal of wreck associated with platforms damaged by Hurricane Ike. 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. On July 31, 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 intend to appeal the decision. Removal of wreck costs are recorded in Oil and natural gas properties and equipment on the Balance Sheet. If we are successful in our appeal, any recoveries from claims made on these Excess Policies related to this issue will be recorded as reductions in this line item, which will reduce the Company s DD&A rate.

Royalties. In 2009, the Company recognized $5.3 million in allowable reductions of cash payments for royalties owed to the Office of Natural Resources Revenue (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, management believes 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. Recognized expenses related to accrued and settled claims, complaints and fines were less than $ 0.1 million for the six months ended June 30, 2013 and $8.4 million for the six months ended June 30, 2012. These expenses are reported in General and administrative expenses on the statement of income and reflect the items noted above and other various claims and complaints. As of June 30, 2013 and December 31, 2012, we have recorded $0.0 million and $1.3 million, respectively, which are included in Accrued liabilities on the balance sheet, for the loss contingencies matters that include the events described above and other minor environmental and litigation matters which we are addressing in the normal course of business.

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. 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 W&T Offshore, Inc. (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
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Condensed Consolidating Balance Sheet as of June 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$ 9,276	$	$	$ 9,276
Receivables:				
Oil and natural gas sales	65,290	15,411	(31)	80,670
Joint interest and other	22,921			22,921
Income taxes	165,239		(125,683)	39,556
Total receivables	253,450	15,411	(125,714)	143,147
Prepaid expenses and other assets	37,214			37,214
Total current assets	299,940	15,411	(125,714)	189,637
Property and equipment at cost:				
Oil and natural gas properties and equipment	6,624,347	385,488		7,009,835
Furniture, fixtures and other	20,848			20,848
Total property and equipment	6,645,195	385,488		7,030,683
Less accumulated depreciation, depletion and amortization	4,614,980	236,993		4,851,973
Net property and equipment	2,030,215	148,495		2,178,710
Restricted deposits for asset retirement obligations	33,469			33,469
Deferred income taxes		8,689	(8,689)	
Other assets	468,352	434,660	(884,814)	18,198
Total assets	$ 2,831,976	$ 607,255	$ (1,019,217)	$ 2,420,014
Liabilities and Shareholders Equity				
Current liabilities:				
Accounts payable	$ 123,101	$	$ (31)	$ 123,070
Undistributed oil and natural gas proceeds	41,788	280		42,068
Asset retirement obligations	74,687			74,687
Accrued liabilities	13,468	126,199	(125,683)	13,984
Deferred income tax current	5,760			5,760
Total current liabilities	258,804	126,479	(125,714)	259,569
Long-term debt	1,099,537			1,099,537
Asset retirement obligations, less current portion	279,295	30,623		309,918
Deferred income taxes	171,637		(8,689)	162,948

Other liabilities	440,525		(434,661)	5,864
Shareholders equity:				
Common stock	1			1
Additional paid-in capital	401,097	231,759	(231,759)	401,097
Retained earnings	205,247	218,394	(218,394)	205,247
Treasury stock, at cost	(24,167)			(24,167)
Total shareholders equity	582,178	450,153	(450,153)	582,178
Total liabilities and shareholders equity	$ 2,831,976	$ 607,255	$ (1,019,217)	$ 2,420,014

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

Condensed Consolidating Balance Sheet as of December 31, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 12,245	$	$	$ 12,245
Receivables:				
Oil and natural gas sales	80,729	17,004		97,733
Joint interest and other	56,439			56,439
Income taxes	163,750		(115,866)	47,884
Total receivables	300,918	17,004	(115,866)	202,056
Deferred income taxes	267			267
Prepaid expenses and other assets	25,555			25,555
Total current assets	338,985	17,004	(115,866)	240,123
Property and equipment at cost:				
Oil and natural gas properties and equipment	6,356,529	337,981		6,694,510
Furniture, fixtures and other	21,786			21,786
Total property and equipment	6,378,315	337,981		6,716,296
Less accumulated depreciation, depletion and amortization	4,461,886	193,955		4,655,841
Net property and equipment	1,916,429	144,026		2,060,455
Restricted deposits for asset retirement obligations	28,466			28,466
Deferred income taxes		13,509	(13,509)	
Other assets	442,540	393,499	(816,096)	19,943
Total assets	$ 2,726,420	$ 568,038	$ (945,471)	$ 2,348,987
Liabilities and Shareholders Equity				
Current liabilities:				
Accounts payable	$ 123,792	$ 93	$	$ 123,885
Undistributed oil and natural gas proceeds	36,791	282		37,073
Asset retirement obligations	92,595		35	92,630
Accrued liabilities	20,755	116,132	(115,866)	21,021
Total current liabilities	273,933	116,507	(115,831)	274,609
Long-term debt	1,087,611			1,087,611
Asset retirement obligations, less current portion	262,524	28,934	(35)	291,423
Deferred income taxes	158,758		(13,509)	145,249

Other liabilities	402,407		(393,499)	8,908
Shareholders equity:				
Common stock	1			1
Additional paid-in capital	396,186	231,759	(231,759)	396,186
Retained earnings	169,167	190,838	(190,838)	169,167
Treasury stock, at cost	(24,167)			(24,167)
Total shareholders equity	541,187	422,597	(422,597)	541,187
Total liabilities and shareholders equity	$ 2,726,420	$ 568,038	$ (945,471)	$ 2,348,987

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

Condensed Consolidating Statement of Income for the Three Months Ended June 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 185,899	$ 49,484	$	$ 235,383
Operating costs and expenses:				
Lease operating expenses	64,977	3,271		68,248
Production taxes	1,780			1,780
Gathering and transportation	3,731	877		4,608
Depreciation, depletion, amortization and accretion	77,951	21,945		99,896
General and administrative expenses	18,758	1,110		19,868
Derivative gain	(12,840)			(12,840)
Total costs and expenses	154,357	27,203		181,560
Operating income	31,542	22,281		53,823
Earnings of affiliates	14,456		(14,456)	
Interest expense:				
Incurred	21,536			21,536
Capitalized	(2,532)			(2,532)
Income before income tax expense	26,994	22,281	(14,456)	34,819
Income tax expense	4,598	7,825		12,423
Net income	$ 22,396	$ 14,456	$ (14,456)	$ 22,396

Condensed Consolidating Statement of Income for the Six Months Ended June 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 395,428	$ 99,177	$	$ 494,605

Operating costs and expenses:				
Lease operating expenses	119,507	8,083		127,590
Production taxes	3,569			3,569
Gathering and transportation	7,393	1,659		9,052
Depreciation, depletion, amortization and accretion	164,366	44,401		208,767
General and administrative expenses	38,363	2,592		40,955
Derivative gain	(9,473)			(9,473)
Total costs and expenses	323,725	56,735		380,460
Operating income	71,703	42,442		114,145
Earnings of affiliates	27,556		(27,556)	
Interest expense:				
Incurred	42,770			42,770
Capitalized	(4,964)			(4,964)
Income before income tax expense	61,453	42,442	(27,556)	76,339
Income tax expense	12,439	14,886		27,325
Net income	$ 49,014	$ 27,556	$ (27,556)	$ 49,014

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

Condensed Consolidating Statement of Income for the Three Months Ended June 30, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 155,595	$ 59,918	$	$ 215,513
Operating costs and expenses:				
Lease operating expenses	53,490	6,786		60,276
Production taxes	1,335			1,335
Gathering and transportation	3,221	889		4,110
Depreciation, depletion, amortization and accretion	63,459	22,482		85,941
General and administrative expenses	14,623			14,623
Derivative gain	(49,872)			(49,872)
Total costs and expenses	86,256	30,157		116,413
Operating income	69,339	29,761		99,100
Earnings of affiliates	19,328		(19,328)	
Interest expense:				
Incurred	14,706			14,706
Capitalized	(3,326)			(3,326)
Income before income tax expense	77,287	29,761	(19,328)	87,720
Income tax expense	23,720	10,433		34,153
Net income	$ 53,567	$ 19,328	$ (19,328)	$ 53,567

Condensed Consolidating Statement of Income for the Six Months Ended June 30, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 332,157	$ 119,242	$	$ 451,399
Operating costs and expenses:				
Lease operating expenses	103,507	13,431		116,938
Production taxes	2,821			2,821

Gathering and transportation	6,704	1,626		8,330
Depreciation, depletion, amortization and accretion	131,082	43,350		174,432
General and administrative expenses	41,510	2,592		44,102
Derivative gain	(10,238)			(10,238)
Total costs and expenses	275,386	60,999		336,385
Operating income	56,771	58,243		115,014
Earnings of affiliates	37,844		(37,844)	
Interest expense:				
Incurred	28,612			28,612
Capitalized	(6,517)			(6,517)
Income before income tax expense	72,520	58,243	(37,844)	92,919
Income tax expense	15,735	20,399		36,134
Net income	$ 56,785	$ 37,844	$ (37,844)	$ 56,785

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

Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Operating activities:				
Net income	$ 49,014	$ 27,556	$ (27,556)	$ 49,014
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	164,366	44,401		208,767
Amortization of debt issuance costs and premium	910			910
Share-based compensation	4,950			4,950
Derivative gain	(9,473)			(9,473)
Cash payments on derivative settlements	(2,310)			(2,310)
Deferred income taxes	18,906	4,820		23,726
Earnings of affiliates	(27,556)		27,556	
Changes in operating assets and liabilities:				
Oil and natural gas receivables	15,439	1,624		17,063
Joint interest and other receivables	33,620			33,620
Insurance receivables	5,015			5,015
Income taxes	(1,487)	10,066		8,579
Prepaid expenses and other assets	(12,381)	(41,160)	41,160	(12,381)
Asset retirement obligation settlements	(32,723)	(163)		(32,886)
Accounts payable, accrued liabilities and other	44,054	(126)	(41,160)	2,768
Net cash provided by operating activities	250,344	47,018		297,362
Investing activities:				
Investment in oil and natural gas properties and equipment	(252,195)	(47,018)		(299,213)
Purchases of furniture, fixtures and other	(981)			(981)
Net cash used in investing activities	(253,176)	(47,018)		(300,194)
Financing activities:				
Borrowings of long-term debt revolving bank credit facility	252,000			252,000
Repayments of long-term debt revolving bank credit facility	(239,000)			(239,000)
Dividends to shareholders	(12,795)			(12,795)
Other	(342)			(342)
Net cash used in financing activities	(137)			(137)

Decrease in cash and cash equivalents	(2,969)			(2,969)
Cash and cash equivalents, beginning of period	12,245			12,245
Cash and cash equivalents, end of period	$ 9,276	$	$	$ 9,276

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

Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Operating activities:				
Net income	$ 56,785	$ 37,844	$ (37,844)	$ 56,785
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	131,082	43,350		174,432
Amortization of debt issuance costs	1,287			1,287
Share-based compensation	5,818			5,818
Derivative gain	(10,238)			(10,238)
Cash payments on derivative settlements	(6,084)			(6,084)
Deferred income taxes	46,010	2,110		48,120
Earnings of affiliates	(37,844)		37,844	
Changes in operating assets and liabilities:				
Oil and natural gas receivables	22,750	3,371		26,121
Joint interest and other receivables	3,630			3,630
Insurance receivables	500			500
Income taxes	(40,351)	18,289		(22,062)
Prepaid expenses and other assets	(14,110)	(71,419)	71,419	(14,110)
Asset retirement obligations	(29,228)			(29,228)
Accounts payable, accrued liabilities and other	79,539	(1,766)	(71,419)	6,354
Net cash provided by operating activities	209,546	31,779		241,325
Investing activities:				
Investment in oil and natural gas properties and equipment	(155,505)	(31,779)		(187,284)
Proceeds from sales of oil and gas properties and equipment	30,453			30,453
Change in restricted cash	(30,763)			(30,763)
Purchases of furniture, fixtures and other	(668)			(668)
Net cash used in investing activities	(156,483)	(31,779)		(188,262)
Financing activities:				
Borrowings of long-term debt revolving bank credit facility	197,000			197,000
Repayments of long-term debt revolving bank credit facility	(234,000)			(234,000)

Dividends to shareholders	(11,898)			(11,898)
Other	(124)			(124)
Net cash used in financing activities	(49,022)			(49,022)
Increase in cash and cash equivalents	4,041			4,041
Cash and cash equivalents, beginning of period	4,512			4,512
Cash and cash equivalents, end of period	$ 8,553	$	$	$ 8,553

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, 2012 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.

Overview

We are an independent oil and natural gas producer with operations offshore in the Gulf of Mexico and onshore in both the Permian Basin of West Texas and in East Texas. We have grown through acquisitions, exploration and development and currently hold working interests in approximately 71 producing offshore fields in federal and state waters (65 producing and six fields capable of producing). We currently have under lease approximately 1.4 million gross acres, including approximately 0.7 million gross acres on the Gulf of Mexico Shelf, approximately 0.5 million gross acres in the deepwater and approximately 0.2 million gross acres onshore in Texas. A substantial majority of our daily production is derived from wells we operate offshore. 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 first half of 2013 were comprised of approximately 40.6% oil and condensate, 11.9% NGLs and 47.5% 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 thousand cubic feet equivalent (Mcfe) for oil, NGLs and natural gas may differ significantly. In the first half of 2013, revenues from the sale of oil and NGLs made up 80.9% of our total revenues, compared to 83.3% in the first half of 2012. For the first half of 2013, our combined total production of oil, condensate, NGLs and natural gas was approximately 3.2% lower on a Mcfe basis than during the same period in 2012, but our total revenues were 9.6% higher in the first half of 2013, driven by higher oil production and higher natural gas prices. See section Results of Operations Six months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012 for additional information on our revenues and production.

In October 2012, we acquired from Newfield certain oil and gas leasehold interests in the Gulf of Mexico. The Newfield Properties consist of leases covering 78 federal offshore blocks on approximately 416,000 gross acres (268,000 net acres) (excluding overriding royalty interests), comprised of 65 blocks in the deepwater, six of which are producing, 10 blocks on the conventional shelf, four of which are producing, and an overriding royalty interest in three deepwater blocks, two of which are producing. Internal estimates of proved reserves associated with the Newfield Properties as of the acquisition date were approximately 7.0 million barrels of oil equivalent (MMBoe) (42.0 billion cubic feet equivalent (Bcfe)), comprised of approximately 61% natural gas, 36% oil and 3% NGLs, all of which were classified as proved developed. Including adjustments from an effective date of July 1, 2012, the adjusted purchase price was $205.7 million and we assumed the ARO associated with the Newfield Properties, which we have estimated to be $31.7 million. The acquisition was initially funded from borrowings under our revolving bank credit facility and cash on hand. Subsequently in the same month, the amounts borrowed under our revolving bank credit facility were paid down with funds provided from the issuance of an additional $300.0 million of 8.50% Senior Notes.

During the first half of 2013, our average realized oil sales price (unhedged) decreased 3.4%, compared to the first half of 2012. Two comparable benchmarks are the unweighted average daily posted spot price of WTI crude oil, which decreased 4.0% from the comparable period, and the unweighted average daily posted spot price of Brent crude oil, which decreased 5.4% from the comparable period. 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 plus a premium depending on the type of crude oil. 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. Starting in the first quarter of 2011 and continuing through the first half of 2013, these various crudes sold at a premium, and sometimes a significant premium, relative to WTI. During the first half of 2013, premiums for Light Louisiana Sweet crude and Heavy Louisiana Sweet crude ranged between \$9.00 and \$22.00 per barrel higher than WTI, with premiums in June 2013 being in the low end of the range at \$9.00 to \$11.00 per barrel. During the first half of 2012, premiums for Light Louisiana Sweet crude and Heavy Louisiana Sweet crude ranged between \$10.00 and \$22.00 per barrel. The average premium spread prior to 2011 was approximately \$2.00 to \$3.00 per barrel. Our offshore oil production competes with foreign-sourced crude oil, which is priced primarily based on the spot price of Brent.

Industry publications have reported that the premiums afforded offshore crudes were primarily due to an oversupply situation at Cushing, Oklahoma, a primary domestic hub for crude oil priced using the WTI benchmark. In response to the Cushing crude oversupply situation, the owners of the Seaway pipeline reversed the flow of crude oil in June 2012 to flow crude from Cushing to Freeport, Texas. In January 2013, the Seaway pipeline capacity was increased from 150,000 barrels per day to 400,000 barrels per day. The owners of the Seaway pipeline have announced plans to construct a parallel pipeline to be completed in the first quarter of 2014, which is expected to increase the capacity to 850,000 barrels per day. Other pipeline projects are underway that, when added to the Seaway pipeline capacity, could bring 1.9 million barrels per day of mid-continent crude oil to the Gulf Coast. That capacity is expected to grow to 2.4 million barrels per day by the end of 2014. This new pipeline capacity for moving mid-continent crude to the Gulf Coast refineries has led to lower price spreads between Brent and WTI as a result of an increase in the price of WTI.

Not only is pipeline capacity increasing, but rail receiving capacity on the East Coast has expanded considerably and is expected to continue to increase. Rail receiving capacity on the Gulf Coast is also expanding, but not at the same rate as the East Coast, as more pipeline capacity is being added to serve that market. As a result of the expanded infrastructure to deliver mid-continent crude oil to domestic refineries by rail, this has also put market pressure to contract the spread of Brent to WTI. This is expected to last until such time as crude production increases to a level in excess of the expanded infrastructure.

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 half of 2013, WTI crude oil prices ranged from \$87.00 to \$98.00 per barrel and Brent crude oil prices ranged from \$97.00 to \$119.00 per barrel. The U.S. Energy Information Administration (EIA) estimates that global production outpaced global consumption during the second quarter of 2013, which is a reversal compared to the last four years. For the full year of 2013, EIA projects global consumption to be higher than production.

Our average realized NGLs sales prices (unhedged) decreased 28.2% during the first half of 2013 compared to the first half of 2012. According to industry sources, increased domestic NGLs production has been the primary factor affecting price realizations. During the first half of 2013, prices for domestic ethane and propane, two common NGL components, decreased 38% and 21%, respectively, from the comparable period in 2012 and other domestic NGLs prices decreased between 4% and 23%. As long as ethane and propane inventories continue to be high and NGLs production continues to be high, we would expect prices for NGLs to be weak. In addition, as long as the crude to natural gas price ratio remains wide, NGLs production may continue to be high, which would continue to put downward pressure on the entire NGLs stream. Many natural gas processing facilities are re-injecting ethane back into the natural gas stream after processing due to increasing ethane supplies. This in turn increases natural gas supplies and has negatively impacted natural gas pricing.

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 and domestic economic conditions, and they have historically been subject to substantial fluctuation. During the first half of 2013, the average realized sales price for our natural gas production increased 46.5% from the comparable period in 2012 to $3.78 per Mcf. A comparable benchmark is the Henry Hub unweighted average daily posted spot price, which increased 59.3% from the comparable period. One major driver was the decrease in temperatures for March 2013, which was 13 degrees colder than in March 2012. Although the price has increased significantly on a percentage basis, the price 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 storage levels building during the injection season, (iii) natural gas continuing to be produced as a by-product in conjunction with the high level of oil drilling, (iv) increasing availability of liquefied natural gas, (v) production efficiency gains being achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling and production techniques and (vi) re-injecting ethane into the natural gas stream as indicated above, which increases the natural gas supply. Per EIA, natural gas working inventories ended June 2013 were 16% below the level at the same time a year ago and approximately flat to the five-year average. EIA has increased their forecast of prices from the prior quarter and expects the Henry Hub gas spot price, which averaged $2.75 per British thermal unit (MMBtu) in 2012, will average $3.76 per MMBtu in 2013 and $3.91 per MMBtu in 2014. EIA projects U.S. consumption to be approximately equal to production for 2013 and projects production to be above consumption in 2014. According to Baker Hughes, the U.S. natural gas rig count decreased from 809 rigs at the beginning of 2012 to 534 by the end of June of 2012. The natural gas rig count continued to decline for the remainder of 2012 and started the year 2013 at 431 rigs. The rig count continued to decrease further and by the end of June 2013, the rig count had decreased to 353 rigs. During January to April, 2013, electricity fueled by natural gas decreased to 26% compared to 30% for the comparable period in response to the cost of coal relative to natural gas. EIA expects this fuel source percentage to be in the 27% to 28% range for 2013 and 2014. Industry sources have indicated that a natural gas price above $4.50 per Mcf 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.

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.

There continues to be many proposed changes in laws, regulations, guidance and policy 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. 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 June 30, (1)				Six Months Ended June 30, (1)			
	2013	2012	Change	%	2013	2012	Change	%
	(In thousands, except percentages and per share data)							
Financial:								
Revenues:								
Oil	$ 168,678	$ 153,838	$ 14,840	9.6%	$ 366,242	$ 323,812	$ 42,430	13.1%
NGLs	15,800	25,941	(10,141)	(39.1)%	34,127	52,325	(18,198)	(34.8)%
Natural gas	49,994	35,683	14,311	40.1%	92,932	74,119	18,813	25.4%
Other	911	51	860	N/A	1,304	1,143	161	14.1%
Total revenues	235,383	215,513	19,870	9.2%	494,605	451,399	43,206	9.6%
Operating costs and expenses:								
Lease operating expenses	68,248	60,276	7,972	13.2%	127,590	116,938	10,652	9.1%
Production taxes	1,780	1,335	445	33.3%	3,569	2,821	748	26.5%
Gathering and transportation	4,608	4,110	498	12.1%	9,052	8,330	722	8.7%
Depreciation, depletion, amortization and accretion	99,896	85,941	13,955	16.2%	208,767	174,432	34,335	19.7%
General and administrative expenses	19,868	14,623	5,245	35.9%	40,955	44,102	(3,147)	(7.1)%
Derivative gain	(12,840)	(49,872)	37,032	(74.3)%	(9,473)	(10,238)	765	(7.5)%
Total costs and expenses	181,560	116,413	65,147	56.0%	380,460	336,385	44,075	13.1%
Operating income	53,823	99,100	(45,277)	(45.7)%	114,145	115,014	(869)	(0.8)%
Interest expense, net of amounts capitalized	19,004	11,380	7,624	67.0%	37,806	22,095	15,711	71.1%
Income before income tax	34,819	87,720	(52,901)	(60.3)%	76,339	92,919	(16,580)	(17.8)%

expense								
Income tax expense	12,423	34,153	(21,730)	(63.6)%	27,325	36,134	(8,809)	(24.4)%
Net income	$ 22,396	$ 53,567	$ (31,171)	(58.2)%	$ 49,014	$ 56,785	$ (7,771)	(13.7)%
Basic and diluted earnings per common share	$ 0.29	$ 0.70	$ (0.41)	(58.6)%	$ 0.64	$ 0.75	$ (0.11)	(14.7)%

(1) In the fourth quarter of 2012, we acquired the Newfield Properties.

	Three Months Ended June 30, (1)				Six Months Ended June 30, (1)			
	2013	2012	Change	%	2013	2012	Change	%
Operating:								
Net sales volumes:								
Oil (MBbls)	1,657	1,451	206	14.2%	3,501	2,991	510	17.1%
NGLs (MBbls)	491	586	(95)	(16.2)%	1,026	1,130	(104)	(9.2)%
Natural gas (MMcf)	11,842	14,320	(2,478)	(17.3)%	24,562	28,696	(4,134)	(14.4)%
Total natural gas and oil (MBoe) (2)	4,122	4,423	(301)	(6.8)%	8,621	8,903	(282)	(3.2)%
Total natural gas and oil (MMcfe) (2)	24,733	26,541	(1,808)	(6.8)%	51,726	53,418	(1,692)	(3.2)%
Average daily equivalent sales (Boe/d) (2)	45,298	48,610	(3,312)	(6.8)%	47,630	48,918	(1,288)	(2.6)%
Average daily equivalent sales (Mcfe/d) (2)	271,786	291,659	(19,873)	(6.8)%	285,779	293,506	(7,727)	(2.6)%
Average realized sales prices (Unhedged):								
Oil ($/Bbl)	$ 101.78	$ 106.04	$ (4.26)	(4.0)%	$ 104.61	$ 108.28	$ (3.67)	(3.4)%
NGLs ($/Bbl)	32.17	44.27	(12.10)	(27.3)%	33.26	46.31	(13.05)	(28.2)%
Natural gas ($/Mcf)	4.22	2.49	1.73	69.5%	3.78	2.58	1.20	46.5%
Oil equivalent ($/Boe) (2)	56.88	48.71	8.17	16.8%	57.22	50.57	6.65	13.2%
Natural gas equivalent ($/Mcfe) (2)	9.48	8.12	1.36	16.7%	9.54	8.43	1.11	13.2%
Average realized sales prices (Hedged) (3):								

Oil ($/Bbl)	$ 102.96	$ 105.84	$ (2.88)	(2.7)%	$ 103.95	$ 106.24	$ (2.29)	(2.2)%
NGLs ($/Bbl)	32.17	44.27	(12.10)	(27.3)%	33.26	46.31	(13.05)	(28.2)%
Natural gas ($/Mcf)	4.22	2.49	1.73	69.5%	3.78	2.58	1.20	46.5%
Oil equivalent ($/Boe) (2)	57.36	48.64	8.72	17.9%	56.95	49.89	7.06	14.2%
Natural gas equivalent ($/Mcfe) (2)	9.56	8.11	1.45	17.9%	9.49	8.31	1.18	14.2%
Average per Mcfe ($/Mcfe) (2):								
Lease operating expenses	$ 2.76	$ 2.27	$ 0.49	21.6%	$ 2.47	$ 2.19	$ 0.28	12.8%
Gathering and transportation	0.19	0.15	0.04	26.7%	0.17	0.16	0.01	6.3%
Production costs	2.95	2.42	0.53	21.9%	2.64	2.35	0.29	12.3%
Production taxes	0.07	0.05	0.02	40.0%	0.07	0.05	0.02	40.0%
Depreciation, depletion, amortization and accretion	4.04	3.24	0.80	24.7%	4.04	3.27	0.77	23.5%
General and administrative expenses	0.80	0.55	0.25	45.5%	0.79	0.83	(0.04)	(4.8)%
	$ 7.86	$ 6.26	$ 1.60	25.6%	$ 7.54	$ 6.50	$ 1.04	16.0%
Total number of wells drilled (gross):								
Offshore	1	2	(1)	(50.0)%	3	2	1	50.0
Onshore	9	19	(10)	(52.6)%	23	37	(14)	(37.8)%
Total number of productive wells drilled (gross):								
Offshore	1	2	(1)	(50.0)%	2	2		0.0%
Onshore	9	19	(10)	(52.6)%	23	37	(14)	(37.8)%

(1) In the fourth quarter of 2012, we acquired the Newfield 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.

(3)

Data for all periods presented includes the effects of realized gains and losses on commodity derivative contracts, none of which qualified for hedge accounting.

Volume measurements:

Boe barrel of oil equivalent	MMcf - million cubic feet
Boe/d barrel of oil equivalent per day	MMcfe - million cubic feet equivalent
MBbls thousand barrels for crude oil, condensate or NGLs	Mcfe/d - thousand cubic feet equivalent per day
MBoe thousand barrels of oil equivalent	

N/A = percentage change not applicable

Three Months Ended June 30, 2013 Compared to the Three Months Ended June 30, 2012

Revenues. Total revenues increased $19.9 million to $235.4 million for the second quarter of 2013 as compared to the same period in 2012. Oil revenues increased $14.8 million, NGLs revenues decreased $10.1 million, natural gas revenues increased $14.3 million and other revenues increased $0.9 million. The oil revenue increase was attributable to a 14.2% increase in sales volumes, partially offset by a 4.0% decrease in the average realized sales price (unhedged) to $101.78 per barrel for the second quarter of 2013 from $106.04 per barrel for the prior year period. The NGLs revenue decrease was attributable to a 27.3% decrease in the average realized sales price to $32.17 per barrel for the second quarter of 2013 from $44.27 per barrel for the prior year period and a decrease of 16.2% in sales volumes from the comparable period. The increase in natural gas revenue resulted from a 69.5% increase in the average realized natural gas sales price to $4.22 per Mcf in the second quarter of 2013 from $2.49 per Mcf for the prior year period, partially offset by a 17.3% decrease in sales volumes from the comparable period. Production for all commodities was positively impacted by production at Ship Shoal 349, onshore properties in West Texas and the Newfield Properties acquired in 2012. Production was negatively impacted for all commodities from natural production declines and from production deferrals affecting up to ten different fields or platforms at various times in the second quarter of 2013. The reasons for the production deferrals included third party pipeline outages, platform maintenance, and various performance issues. We estimate production deferrals were 3.2 Bcfe during the second quarter of 2013, ranging from 30 MMcfe/d to 90 MMcfe/d. Specifically, production at Mississippi Canyon 506 Wrigley continues to be deferred as a result of maintenance at Shell s Cognac platform and related pipelines. Also, production was shut-in at our East Cameron 321 platform for water treating upgrades and oil and gas pipeline issues, and two wells in our Fairway field are shut-in awaiting workovers. In addition, third party sales pipelines were shut-in at Mississippi Canyon 800 Gladden and Ship Shoal 349 Mahogany at various times in the 2013 second quarter.

Revenues from oil and liquids as a percent of our total revenues were 78.4% for the second quarter of 2013 compared to 83.4% for the prior year period. NGLs realized prices as a percent of oil realized prices decreased to 31.6% for the second quarter of 2013 compared to 41.7% for the comparable period.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workovers and maintenance on our facilities, increased $8.0 million to $68.2 million in the second quarter of 2013 compared to the prior year period. On a per Mcfe basis, lease operating expenses increased to $2.76 per Mcfe during the second quarter 2013 compared to $2.27 per Mcfe during the comparable 2012 period. On a component basis, workover expense increased $11.4 million primarily as a result of a rig workover on a well at our Main Pass 69 field. Conversely, expenditures on facilities maintenance was lower by $1.4 million, base lease operating expenses decreased by $1.2 million, and insurance premiums decreased $0.8 million. The decrease in facilities expense was attributable to multiple projects occurring in 2012 that did not repeat in 2013, partially offset by work at our Yellowhammer Plant. The decrease in base lease operating expenses is due to, among other things, lower operating expenses at the Fairway field and the Yellowhammer plant and reimbursement resulting from an audit of joint venture billings.

Production taxes. Production taxes increased to $1.8 million in the second quarter of 2013 compared to $1.3 million in 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 $0.5 million for the second quarter of 2013 compared to the prior year period.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to $4.04 per Mcfe for the second quarter of 2013 from $3.24 per Mcfe in the prior year period. On a nominal basis, DD&A

increased to $99.9 million for the second quarter of 2013 from $85.9 million in the prior year period. DD&A on a per Mcfe basis and nominal basis increased primarily due to costs capitalized to the full cost pool from the unevaluated pool and from increases in our ARO estimates without a corresponding increase in proved reserves, which primarily occurred in the latter part of 2012. In addition, we incurred development costs during 2012 and during the first half of 2013 above previous estimates, and as a result, we increased our estimates of future development costs. The Newfield Properties also increased the DD&A rate on a per Mcfe basis.

General and administrative expenses. G&A increased to $19.9 million for the second quarter of 2013 from $14.6 million for the prior year period primarily due to increases in accrued incentive compensation, timing of bond premiums, higher consulting services costs related to drilling operations and lower overhead billed to joint interest partners. The second quarter of 2012 reflected no accrual for cash-based incentive compensation. G&A on a per Mcfe basis was $0.80 per Mcfe for the second quarter of 2013, compared to $0.55 per Mcfe for the prior year period.

Derivative gain. For the second quarter of 2013 and 2012, our derivative net gains were $12.8 million and $49.9 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 current year and next year, changes in the fair value for all open contracts are recorded currently. For the second quarter of 2013, the net gain was comprised of a $1.9 million realized gain and a $10.9 million unrealized gain. For the second quarter of 2012, the net gain consisted of a realized loss of $0.3 million and an unrealized gain of $50.2 million. For additional information about our derivatives, refer to Item 1 Financial Statements Note 5 Derivative Financial Instruments.

Interest expense. Interest expense incurred increased to $21.5 million for the second quarter of 2013 from $14.7 million for the prior year period. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in the second quarter of 2013 compared to $600.0 million in the prior year period due to the issuance of 8.50% Senior Notes during October 2012. During the second quarter of 2013 and 2012, $2.5 million and $3.3 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying unevaluated properties to the full cost pool during the fourth quarter of 2012.

Income tax expense. Income tax expense decreased to $12.4 million for the second quarter of 2013 compared to $34.2 million for the same period of 2012 primarily attributable to lower pre-tax income. Our effective tax rate for the three months ended June 30, 2013 was 35.7% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes. Our effective tax rate for the second quarter of 2012 was 38.9% and differed from the federal statutory rate of 35.0% primarily as a result of the recapture of deductions for qualified domestic production activities under Section 199 of the IRC as a result of loss carrybacks to prior years.

Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012

Revenues. Total revenues increased $43.2 million to $494.6 million for the first half of 2013 as compared to the same period in 2012. Oil revenues increased $42.4 million, NGLs revenues decreased $18.2 million, natural gas revenues increased $18.8 million and other revenues increased $0.2 million. The oil revenue increase was attributable to a 17.1% increase in sales volumes, partially offset by a 3.4% decrease in the average realized sales price (unhedged) to $104.61 per barrel for the first half of 2013 from $108.28 per barrel for the prior year period. The NGLs revenue decrease was attributable to a 28.2% decrease in the average realized sales price to $33.26 per barrel for the first half of 2013 from $46.31 per barrel for the prior year period and a decrease of 9.2% in sales volumes from the comparable period. The increase in natural gas revenue resulted from a 46.5% increase in the average realized natural gas sales price to $3.78 per Mcf in the first half of 2013 from $2.58 per Mcf for the prior year period, partially offset by a 14.4% decrease in sales volumes from the comparable period. Production for all commodities was positively impacted by production at Ship Shoal 349, onshore properties in West Texas and the Newfield Properties acquired in 2012. Production was negatively impacted for all commodities from natural production declines and from production deferrals affecting up to ten different fields or platforms at various times in the first half of 2013. The reasons for the production deferrals included third party pipeline outages, platform maintenance, and various performance issues. We estimate production deferrals were 4.6 Bcfe during the first half of 2013, ranging from 15 MMcfe/d to 90 MMcfe/d. Specifically, production at Mississippi Canyon 506 Wrigley was deferred as a result of maintenance at Shell s Cognac platform and related pipelines. Also, in the second quarter of 2013, production was shut-in at our East Cameron 321 platform for water treating upgrades and oil and gas pipeline issues, and two wells in our Fairway field are shut-in awaiting workovers. In addition, third party sales pipelines were shut-in at Mississippi Canyon 800 Gladden and Ship Shoal 349 Mahogany at various times in the second quarter of 2013.

Revenues from oil and liquids as a percent of our total revenues were 80.9% for the first half of 2013 compared to 83.3% for the prior year period. NGLs realized prices as a percent of oil realized prices decreased to 31.8% for the first half of 2013 compared to 42.8% for the comparable period.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workovers and maintenance on our facilities, increased $10.7 million to $127.6 million in the first half of 2013 compared to the prior year period. On a per Mcfe basis, lease operating expenses increased to $2.47 per Mcfe during the first half 2013 compared to $2.19 per Mcfe during the comparable 2012 period. On a component basis, workover expense increased $9.9 million primarily as a result of a rig workover on a well at our Main Pass 69 field. In addition, facilities expense increased $2.1 million, which was primarily attributable to work at our Yellowhammer Plant combined with smaller projects at various locations. As a partial offset, insurance premiums and base lease operating expenses decreased $0.8 million and $0.5 million, respectively.

Production taxes. Production taxes increased to $3.6 million in the first half of 2013 compared to $2.8 million in 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 $0.7 million for the first half of 2013 compared to the prior year period.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to $4.04 per Mcfe for the first half of 2013 from $3.27 per Mcfe in the prior year period. On a nominal basis, DD&A increased to $208.8 million for the first half of 2013 from $174.4 million in the prior year period. DD&A on a per Mcfe basis and nominal basis increased primarily due to costs capitalized to the full cost pool from both the unevaluated pool and from increases in our ARO estimates without a corresponding increase in proved reserves, which primarily occurred in the latter part of 2012. In addition, we incurred development costs during 2012 and during the first half of 2013 above previous estimates, and as a result, we increased our estimates of future development costs. The Newfield Properties also increased the DD&A rate on a per Mcfe basis.

General and administrative expenses. G&A decreased to $41.0 million for the first half of 2013 from $44.1 million for the prior year period primarily due to lower litigation and settlement cost, partially offset by increases in accrued incentive compensation expense and consulting services related to drilling operations. G&A on a per Mcfe basis was $0.79 per Mcfe for the first half of 2013, compared to $0.83 per Mcfe for the prior year period.

Derivative gain. For the first half of 2013 and 2012, our derivative net gains were $9.5 million and $10.2 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 current year and next year, changes in the fair value for all open contracts are recorded currently. For the first half of 2013, the net gain was comprised of a $2.3 million realized loss and an $11.8 million unrealized gain. For the first half of 2012, the net gain was comprised of a $6.1 million realized loss and a $16.3 million unrealized gain. For additional information about our derivatives, refer to Item 1 Financial Statements Note 5 Derivative Financial Instruments.

Interest expense. Interest expense incurred increased to $42.8 million for the first half of 2013 from $28.6 million for the prior year period. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in the first half of 2013 compared to $600.0 million in the prior year period due to the issuance of 8.50% Senior Notes during October 2012. During the first half of 2013 and 2012, $5.0 million and $6.5 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying unevaluated properties to the full cost pool during the fourth quarter of 2012.

Income tax expense. Income tax expense decreased to $27.3 million for the first half of 2013 compared to $36.1 million for the same period of 2012 primarily attributable to lower pre-tax income. Our effective tax rate for the first half of 2013 was 35.8% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes. Our effective tax rate for the first half of 2012 was 38.9% and differed from the federal statutory rate of 35.0% primarily as a result of the recapture of deductions for qualified domestic production activities under Section 199 of the IRC as a result of loss carrybacks to prior years.

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

Cash flow and working capital. Net cash provided by operating activities for the first half of 2013 was $297.4 million compared to $241.3 million for the first half of 2012. The change was primarily due to higher revenues associated with increased production volumes for oil, increased realized prices for natural gas, collections on joint interest receivables and lower income tax payments, partially offset by higher lease operating expense and interest expense. Our combined average realized sales price (hedged) per Mcfe was 14.2% higher than the comparable 2012 period due to oil increasing from 34% to 41% of our combined production and higher natural gas prices. Our combined production of oil, NGLs and natural gas on a Mcfe basis during the first half of 2013 decreased 3.2% from the first half of 2012.

Net cash used in investing activities during the first half of 2013 and 2012 was $300.2 million and $188.3 million, respectively, which represents our investments in both offshore and onshore oil and gas properties. The increase is primarily attributable to an increase in offshore drilling activity. There were no acquisitions completed in either period.

Net cash used in financing activities was $0.1 million and $49.0 million during the first half of 2013 and 2012, respectively. The net cash used during the first half of 2013 was primarily attributable to dividend payments of $12.8 million and was offset by net borrowings on the revolving bank credit facility of $13.0 million. The net cash used in the first half of 2012 was attributable to net pay downs on the revolving bank credit facility and dividend payments.

At June 30, 2013, we had a cash balance of $9.3 million and $616.9 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $800.0 million as of June 30, 2013.

Credit Agreement and long-term debt. At June 30, 2013 and December 31, 2012, $183.0 million and $170.0 million, respectively, were outstanding under our revolving bank credit facility. During the six months ended June 30, 2013, the outstanding borrowings on our revolving bank credit facility ranged from $143.0 million to $218.0 million. At June 30, 2013 and December 31, 2012, $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. For additional information about our long-term debt, refer to Financial Statements Note 6 Long-Term Debt under Part I, Item 1 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 June 30, 2013.

Derivatives. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving loan facility. As of June 30, 2013, our derivative instruments outstanding consisted of oil contracts relating to approximately 1.4 million barrels (MMBbls) and 0.7 MMBbls of our anticipated production for the balance of 2013 and for 2014, respectively. In July 2013, we entered into additional derivative contracts related to production in 2014. See Financial Statements Note 5 Derivative Financial Instruments under Part I, Item 1 of this Form 10-Q for additional information.

Hurricane Remediation, Insurance Claims and Insurance. During the third quarter of 2008, Hurricane Ike caused substantial property damage and we continue to incur costs and submit claims to our insurance underwriters related to repairing such damage. Our Energy Package that was in effect on the occurrence date of Hurricane Ike had a retention requirement of $10.0 million per occurrence, which has been satisfied, and coverage policy limits of $150.0 million for damage due to named windstorms (excluding damage at certain facilities) and our Excess Policies in effect on the occurrence date of Hurricane Ike had coverage limits of $250.0 million for, among other things, removal of wreckage if mandated by any governmental authority.

As of June 30, 2013, we have recorded in ARO an estimate of $6.6 million for additional costs to be incurred related to Hurricane Ike and we have estimated this work will be completed within 12 months. Through June 30, 2013, we have received cash from our insurance carrier related to Hurricane Ike claims totaling $147.2 million. In addition, we have incurred removal of wreck costs related to Hurricane Ike, but our insurance carriers for our Excess Policies have disputed coverage terms related to removal of wreck costs, as described below.

During the fourth quarter of 2012, underwriters of our 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 such Excess Policies cover removal of wreck and debris claims arising from Hurricane Ike to the extent we have first exhausted the limits of our Energy Package policies with only removal of wreck and debris claims. The court consolidated the various suits filed by underwriters. We have not yet filed any claim under such Excess Policies. As of June 30, 2013, we have spent $44.5 million and expect to incur an additional $2.6 million of costs for removal of wreck associated with platforms damaged by Hurricane Ike. 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. On July 31, 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 intend to appeal the decision. Removal of wreck costs are recorded in Oil and natural gas properties and equipment on the Balance Sheet. If we are successful in our appeal, any recoveries from claims made on these Excess Policies related to this issue will be recorded as reductions in this line item, which will reduce our DD&A rate.

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 approximately 96% of our estimated future net revenues discounted at 10% (PV-10) attributable to our Gulf of Mexico properties as of June 30, 2013 are on platforms and subsea wells that are covered under our current insurance policies for named windstorm damage. There are certain other properties we have deemed as non-core and are not covered for named windstorm damage.

Our general and excess liability policies, effective until May 1, 2014, 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 . 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.

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:

	Six Months Ended June 30,	
	2013	2012
	(in thousands)	
Exploration (1)	$ 109,283	$ 36,939
Development (1)	168,116	141,989

Seismic, capitalized interest, other leasehold costs	21,814	8,356
Acquisitions and investments in oil and gas property/equipment	$ 299,213	$ 187,284

(1) Reported geographically in the subsequent table.

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

	Six Months Ended June 30,	
	2013	2012
	(in thousands)	
Conventional shelf	$ 88,473	$ 44,246
Deepwater	49,001	31,128
Deep shelf	45,791	2,418
Onshore	94,134	101,136
Exploration and development capital expenditures	$ 277,399	$ 178,928

Our first half 2013 and 2012 capital expenditures 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:

	Six Months Ended June 30, 2013		2012	
	Gross	Net	Gross	Net
Development wells:				
Offshore wells:				
Productive	2	2.0	2	2.0
Non-productive				
Onshore wells:				
Productive	19	18.9	21	21.0
Non-productive				
Total development wells	21	20.9	23	23.0
Exploration wells:				
Offshore wells:				
Productive				
Non Productive	1	1.0		
Onshore wells:				
Productive	4	3.9	16	13.1
Non-productive				
Total exploration wells	5	4.9	16	13.1
Total wells	26	25.8	39	36.1

Exploration activities During July 2013, the A-14 well at our Ship Shoal 349 Mahogany field resulted in a deep shelf subsalt discovery and had an initial flow back rate of 3,030 barrels of oil per day and 5.6 MMcf of natural gas per day, for a total of approximately 4,000 Boe/d (3,300 Boe/d to W&T, net of royalty). During the first week of August, the well s peak production rate was 4,644 Boe/d (3,870 Boe/d to W&T, net of royalty). We hold a 100% working interest in the field. The well is currently producing from the lowest of four sands that are believed capable of production in commercial quantities.

Acquisitions and funding We intend to continue to pursue acquisitions and joint venture opportunities during 2013 and beyond should we identify attractive opportunities. We are actively evaluating opportunities and seek to complement our drilling and development projects with acquisitions providing acceptable rates of return. We anticipate funding our 2013 capital budget and acquisitions with internally generated cash flow, cash on hand, borrowings under our revolving loan facility, and by accessing the capital markets to the extent necessary.

Lease acquisitions. During the first half of 2013, we acquired leasehold interest in approximately 2,200 acres in the West Texas Permian Basin, which is near our existing holdings and increased our acreage position by approximately 10% in that area. We also acquired leasehold interest in approximately 8,700 acres in the Gulf of Mexico through the U.S. government s lease sale process during the first half of 2013.

Capital Expenditure Budget for 2013. Our total capital expenditure budget is $450.0 million for 2013. The capital expenditure budget does not include any potential acquisitions. The budget is generally allocated as 63% for exploration and 37% for development and these percentages include amounts for facilities capital, recompletions, seismic data, leasehold interests and other items. Geographically, the budget includes 63% for offshore properties and 37% for onshore properties. Our 2013 capital budget is subject to change as conditions warrant and we strive to be as flexible as possible.

Income taxes. During the first half of 2013, we made no income tax payments and received $4.9 million of refunds. During the first half of 2012, we made income tax payments of $10.4 million and received refunds of $0.4 million. For the remainder of 2013, we expect a substantial amount of our income tax will be deferred and expect payments to be primarily related to alternative minimum tax. In August 2013, we received tax refunds of $54.2 million attributable to tax loss carrybacks to 2010 and 2011, of which $9.5 million was unrecorded as of June 30, 2013 due to uncertain tax positions. After the 2012 net operating loss carryback, the amount of remaining net operating losses generated in 2012 available to offset future taxable income in 2013 and forward is $41.4 million. We also have $21.6 million of alternative minimum tax credit carryforwards available to be utilized in 2013 and forward.

Dividends. During the first half of 2013 and 2012, we paid regular cash dividends per common share of $0.17 and $0.16, respectively. On August 7, 2013, our board of directors declared a cash dividend of $0.09 per common share, payable on September 12, 2013 to shareholders of record on August 22, 2013.

Contractual obligations. Updated information on certain contractual obligations is provided in Financial Statements Note 4 Asset Retirement Obligations and Financial Statements Note 6 Long-Term Debt under Part I, Item 1 of this Form 10-Q. As of June 30, 2013, drilling rig commitments were approximately $28.0 million compared to $36.5 million as of December 31, 2012. The current drilling rig commitments all expire within one year from June 30, 2013. In addition, we entered into an agreement, effective April 1, 2013 and expiring March 31, 2017, with a group of companies for access to a comprehensive well-containment solution made up of certain equipment, procedures, and processes to be activated in the event of an offshore spill. The remaining commitment as of June 30, 2013 was $6.7 million. Other contractual obligations as of June 30, 2013 did not change materially, except for scheduled utilization, from the disclosures in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2012.

Critical Accounting Policies

Our significant accounting policies are summarized in Note 1 of Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the year ended December 31, 2012. Also refer to the Notes to Condensed Consolidated Financial Statements under Part 1, Item 1 of this Form 10-Q.

Recent Accounting Pronouncements

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities which applies to certain items in the statement of financial position (balance sheet), and was further clarified in January 2013 by ASU 2013-01, Balance Sheet (Topic 210):Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which clarified the scope of ASU 2011-11 to derivative instruments, repurchase agreements and securities lending transactions. The effective date for the amendments is for annual periods beginning after January 1, 2013, and interim periods within those annual periods. ASU 2011-11 requires disclosures of the gross and net amounts for items eligible for offset in the balance sheet. Although our derivative financial instruments are subject to master netting agreements, we record our derivative financial instruments on a gross basis by contract; therefore, the ASUs did not significantly affect our disclosures. Other items of the ASUs were not applicable to us.

In February 2013, the FASB issued ASU 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date, which requires an entity that is joint and severally liable to measure the obligation as the sum of the amount the entity has agreed with co-obligors to pay and any additional amount it expects to pay on behalf of one or more co-obligors. Required disclosures include a description of the nature of the arrangement, how the liability arose, the relationship with co-obligors and the terms and conditions of the arrangement. The effective date for the amendment is for annual periods beginning after December 15, 2013, and interim periods within those annual periods. The amendment is to be applied retrospectively to all prior periods presented. We are currently assessing the impact of ASU 2013-04 to determine the effects on the balance sheet and disclosures, if any.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the first half of 2013 did not change materially from the disclosures in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2012. 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, 2012.

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 2013 and the year 2014. As of June 30, 2013, these derivative contracts had a notional quantity of 2.1 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 Financial Statements Note 5 Derivative Financial Instruments under Part I, Item 1 of this Form 10-Q for additional information.

Interest Rate Risk. As of June 30, 2013, we had $183.0 million outstanding on our revolving bank credit facility. The revolving bank credit facility has a variable interest rate, which is primarily impacted by the rates for the LIBOR and the margin, which ranges from 2.00% 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 Chief Executive Officer and Chief Financial Officer, 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 Chief Executive Officer and Chief Financial Officer, 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 Chief Executive Officer and Chief Financial Officer have each concluded that as of June 30, 2013 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 Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

During the quarter ended June 30, 2013, 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

Cameron Parish Louisiana Claim. Since 2009, certain Cameron Parish landowners have filed suits in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and its Chief Executive Officer, Tracy W. Krohn, as well as several other defendants unrelated to us. In their lawsuits, plaintiffs alleged that property they own has been contaminated or otherwise damaged by the defendants oil and gas exploration and production activities and they are seeking compensatory and punitive damages. During 2012 and for the six months ended June 30, 2013, we settled claims with certain landowners and paid $11.3 million.

Qui Tam Litigation. On September 21, 2012, we were served with a complaint in a qui tam action filed under the federal False Claims Act by an employee of one of our contractors. The lawsuit, United States ex rel. Comeaux v. W&T Offshore, Inc., et al.; CA No. 10-494, was filed in the United States District Court for the Eastern District of Louisiana, against us and three other working interest owners related to claims associated with three of our operated production platforms. A qui tam action, also known as a whistleblower action, is a lawsuit brought by a private citizen seeking civil penalties or damages against a person or company on behalf of the government for alleged violations of law. If the claims are successful, the person filing the suit may recover a percentage of the damages or penalty from the lawsuit as a reward for exposing a wrongdoing and recovering funds on behalf of the government. The complaint was originally filed in 2010 but kept under confidential seal in order for the federal government to decide if it wished to intervene and take over the prosecution of the qui tam action. The government declined to intervene in this suit and the complaint was unsealed and made public in June 2012, thereby giving the plaintiff the opportunity to pursue the claims on behalf of the government. The plaintiff is pursuing the claim.

The complaint alleges that environmental violations at three of our operated production platforms in the Gulf of Mexico violate the federal offshore lease provisions so that we, among other things, wrongfully retained benefits under the applicable leases. The alleged environmental violations include allegations of discharges of relatively small amounts of oil into the Gulf of Mexico, the failure to report and record such discharges, and falsification of certain produced water samples and related reports required under federal law. The events are alleged to have occurred in 2009. These are largely the same underlying environmental allegations that resulted in the plea agreement described in the audited financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2012. We have filed a motion to dismiss the plaintiff s claims. The plaintiff dismissed his claims against the three other working interest owners after they filed motions to dismiss. The plaintiff conceded that certain of his claims should be dismissed in his reply to our motion to dismiss. By order dated August 6, 2013, the court granted the Company s motion to dismiss plaintiff s claims without prejudice and allowed plaintiff twenty days to amend his complaint to remedy the deficiencies in his claims. The court will dismiss with prejudice if the plaintiff cannot or does not correct the deficiencies in his claims.

We intend to vigorously defend the claims made in this lawsuit. While we have determined that the likelihood of an adverse outcome may be reasonably possible, the range of potential loss cannot yet be estimated, and accordingly, no accrual has been made.

Insurance Claims. During the fourth quarter of 2012, underwriters of our 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 such Excess Policies cover removal of wreck and debris claims arising from Hurricane Ike to the extent we have first exhausted the limits of our Energy Package policies with only removal of wreck and debris claims. The court consolidated the various suits filed by underwriters. We have not yet filed any claim under such Excess Policies. As of June 30, 2013, we have spent

$44.5 million and expect to incur an additional $2.6 million of costs for removal of wreck associated with platforms damaged by Hurricane Ike. 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. On July 31, 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 intend to appeal the decision. Removal of wreck costs are recorded in Oil and natural gas properties and equipment on the Balance Sheet. If we are successful in our appeal, any recoveries from claims made on these Excess Policies related to this issue will be recorded as reductions in this line item, which will reduce our DD&A rate.

From time to time, we are party to other litigation or legal and administrative proceedings that we consider to be a part of the ordinary course of our business. Except for the matters noted above, we are not involved in any legal proceedings nor are we party to any pending or threatened claims that could, individually or in the aggregate, reasonably be expected to have a material adverse effect on our financial condition, cash flow or results of operations.

Item 1A. Risk Factors

Investors should carefully consider the risk factors included under Risk Factors under Part I, Item 1A in our Annual Report on Form 10-K for the year ended December 31, 2012, 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 in our Annual Report on Form 10-K for the year ended December 31, 2012.

Item 6. Exhibits

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

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on August 8, 2013.

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@	First Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company s Definitive Proxy Statement on Schedule 14A filed April 3, 2013).
10.2@	Second Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company s Definitive Proxy Statement on Schedule 14A filed April 3, 2013).
10.3*@	Form of 2013 Executive Annual Cash Award.
10.4*@	Form of 2013 RSU Executive Award.
10.5*@	Form of 2013 Time Based RSU Executive Agreement.
10.6*@	Tracy W. Krohn 2013 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.