

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

Form 10-K

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

For the fiscal year ended December 31, 2015

or

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

For the transition period from _____ to _____

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

Texas
(State or other jurisdiction of incorporation or organization)

Nine Greenway Plaza, Suite 300
Houston, Texas
(Address of principal executive offices)

72-1121985
(I.R.S. Employer
Identification Number)

77046-0908

(Zip Code)

(713) 626-8525

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class

Name of Each Exchange on Which Registered

Common Stock, par value \$0.00001

New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer Accelerated filer

Non-accelerated filer Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

The aggregate market value of the registrant's common stock held by non-affiliates was approximately \$191,676,000 based on the closing sale price of \$5.48 per share as reported by the New York Stock Exchange on June 30, 2015.

The number of shares of the registrant's common stock outstanding on March 3, 2016 was 76,506,489.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement relating to the Annual Meeting of Shareholders, to be filed within 120 days of the end of the fiscal year covered by this report, are incorporated by reference into Part III of this Form 10-K.

W&T OFFSHORE, INC.
TABLE OF CONTENTS

	<u>Page</u>
Item 1. Business	1
Item 1A. Risk Factors	10
Item 1B. Unresolved Staff Comments	29
Item 2. Properties	30
Item 3. Legal Proceedings	44
Executive Officers of the Registrant	46
Item 4. Mine Safety Disclosures	46
<u>PART II</u>	
Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	47
Item 6. Selected Financial Data	50
Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations	55
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	74
Item 8. Financial Statements and Supplementary Data	75
Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	132
Item 9A. Controls and Procedures	132
Item 9B. Other Information	132
<u>PART III</u>	
Item 10. Directors, Executive Officers and Corporate Governance	133
Item 11. Executive Compensation	133
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	133
Item 13. Certain Relationships and Related Transactions, and Director Independence	133
Item 14. Principal Accountant Fees and Services	133
<u>PART IV</u>	
Item 15. Exhibits and Financial Statement Schedules	134
Signatures	141
Index to Consolidated Financial Statements	75
Glossary of Oil and Natural Gas Terms	138

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K 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. These forward-looking statements involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate under 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 this Annual Report on Form 10-K and may be discussed or updated from time to time in subsequent reports filed with the Securities and Exchange Commission ("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 required by law. Unless the context requires otherwise, references in this Annual Report on Form 10-K to "W&T," "we," "us," "our" and the "Company" refer to W&T Offshore, Inc. and its consolidated subsidiaries.

PART I

Item 1. *Business*

W&T Offshore, Inc. is an independent oil and natural gas producer, active in the exploration, development and acquisition of oil and natural gas properties in the Gulf of Mexico. In October 2015, we disposed of substantially all of our onshore oil and natural gas interests with the sale of our Yellow Rose field in the Permian Basin. We retained an overriding royalty interest in the Yellow Rose field production. W&T Offshore, Inc. is a Texas corporation originally organized as a Nevada corporation in 1988, and successor by merger to W&T Oil Properties, Inc., a Louisiana corporation organized in 1983. Our interest in fields, leases, structures and equipment are primarily owned by the parent company, W&T Offshore, Inc. and our wholly-owned subsidiary, W & T Energy VI, LLC, a Delaware limited liability company.

The Gulf of Mexico is an area where we have developed significant technical expertise and where high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve a rapid return on our invested capital. We have leveraged our significant experience in the conventional shelf (water depths of less than 500 feet) to develop higher impact capital projects in the Gulf of Mexico in both the deepwater (water depths in excess of 500 feet) and the deep shelf (well depths in excess of 15,000 feet and water depths of less than 500 feet). We have acquired rights to explore and develop new prospects and acquired existing oil and natural gas properties in both the deepwater and the deep shelf, while at the same time continuing our focus on the conventional shelf. Over the last several years, we have shifted our focus more toward the deepwater. In the deepwater, we have completed numerous acquisitions and drilled both exploration and development wells, and our deepwater acreage has expanded considerably over the last several years.

As of December 31, 2015, we have interests in offshore leases covering approximately 900,000 gross acres (550,000 net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. On a gross acreage basis, the conventional shelf constitutes approximately 550,000 acres and deepwater constitutes approximately 350,000 acres of our offshore acreage.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), our independent petroleum consultants, our total proved reserves at December 31, 2015 were 76.4 million barrels of oil equivalent (“MMBoe”) or 458.1 billion cubic feet of gas equivalent (“Bcfe”). Approximately 75% of our proved reserves as of such date were classified as proved developed producing, 15% as proved developed non-producing and 10% as proved undeveloped. Classified by product, our proved reserves at December 31, 2015 were 46% crude oil, 9% natural gas liquids (“NGLs”) and 45% natural gas. These percentages were determined using the energy-equivalent ratio of six thousand cubic feet (“Mcf”) of natural gas to one barrel (“Bbl”) of crude oil, condensate or NGLs. This energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for crude oil, NGLs and natural gas may differ significantly. Our total proved reserves had an estimated present value of future net revenues discounted at 10% (“PV-10”) of \$966 million before consideration of cash outflows related to asset retirement obligations (“ARO”). Our PV-10 after considering future cash outflows related to ARO was \$614 million, and our standardized measure of discounted future cash flows was also \$614 million as of December 31, 2015, as no future income taxes were estimated to be paid due to our present tax position. Neither PV-10 nor PV-10 after ARO is a financial measure defined under generally accepted accounting principles (“GAAP”). For additional information about our proved reserves and a reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows, see *Properties – Proved Reserves* under Part I, Item 2 in this Form 10-K.

We seek to increase our reserves through acquisitions, exploratory and infill drilling, recompletions and workovers. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to add reserves, production and cash flow post-acquisition. Our acquisition team strives to find properties that will fit our profile and that we believe will add strategic and financial value to our company.

In September 2014, we acquired an additional ownership interest in the Mobile Bay blocks 113 and 132 located in Alabama state waters (the “Fairway Field”) and the associated Yellowhammer gas processing plant (collectively “Fairway”), which increased our ownership interest from 64.3% to 100%.

In May 2014, we acquired from Woodside Energy (USA) Inc. (“Woodside”) certain oil and gas leasehold interests in the Gulf of Mexico (the “Woodside Properties”). The Woodside Properties consist of a 20% non-operated working interest in the producing Neptune field (deepwater Atwater Valley blocks 574, 575 and 618), along with an interest in the Neptune tension-leg platform, associated production facilities and various interests in 24 other deepwater lease blocks.

In November and December 2013, we acquired from Callon Petroleum Operating Company (“Callon”) certain oil and gas leasehold interests in the Gulf of Mexico (the “Callon Properties”). The Callon Properties consist of a 15% non-operated working interest in the Medusa field (deepwater Mississippi Canyon blocks 538 and 582), interest in associated production facilities and various interests in other non-operated fields.

Under current commodity pricing conditions, we expect in the near term to continue to focus on conserving capital and maintaining liquidity. Accordingly, while we will continue to evaluate opportunistic acquisitions, we expect that our acquisition activities will be reduced until the outlook for the future commodity pricing environment improves or unless financing is available on reasonable terms that would not significantly impair our available liquidity.

From time to time, as part of our business strategy, we sell various properties. In October 2015, we sold our ownership interests in the Yellow Rose onshore field to Ajax Resources, LLC (“Ajax”). The field is located in the Permian Basin, West Texas, and covers approximately 25,800 net acres. In addition to the cash purchase price, we were assigned a non-expense bearing overriding royalty interest (“ORRI”) in production from the working interests assigned to Ajax, which percentage varies on a sliding scale from one percent for each month that the prompt month New York Mercantile Exchange (“NYMEX”) trading price for light sweet crude oil is at or below \$70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than \$90.00 per barrel. Our internal estimate of the assigned proved reserves at the date of the sale to Ajax was 19.0 MMBoe, consisting of approximately 71% oil, 11% NGL and 18% natural gas. In 2014, we did not have any significant property sales. In 2013, we sold our non-operated working interests in the Green Canyon 60 field, the Green Canyon 19 field and the West Delta area block 29, all located in the Gulf of Mexico.

Additional information on acquisitions and divestitures can be found under *Properties* in Part I, Item 2, *Management’s Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7, and in *Financial Statements and Supplementary Data – Note 2 – Acquisitions and Divestitures* under Part II, Item 8 in this Form 10-K.

Our exploration efforts have historically been in areas in reasonably close proximity to known proved reserves, but starting in 2012, some of our exploration projects were higher risk deepwater projects with potentially higher returns than our previous risk/reward profile. The investment associated with drilling an offshore well and future development of an offshore project principally depends upon water depth, the depth of the well, the complexity of the geological formations involved and whether the well or project can be connected to existing infrastructure or will require additional investment in infrastructure. Deepwater and deep shelf drilling projects can be substantially more capital intensive than those on the conventional shelf and onshore. Certain risks are inherent in our business specifically and in the oil and natural gas industry generally, any one of which can negatively impact our rate of return on shareholders’ equity if it occurs. When projects are extremely capital intensive and involve substantial risk, we often seek participants to share the risk. We completed five, six, and five offshore wells (gross) and five, 33, and 40 onshore wells (gross) in 2015, 2014 and 2013, respectively.

We generally sell our crude oil, NGLs and natural gas at the wellhead at current market prices or transport our production to “pooling points” where it is sold. We are required to pay gathering and transportation costs with respect to a majority of our products. Our products are marketed several different ways depending upon a number of factors including the availability of purchasers at the wellhead, the availability and cost of pipelines near the well or related production platforms, the availability of third-party processing capacity, market prices, pipeline constraints and operational flexibility.

Due to the continued deterioration of commodity prices and the outlook for the remainder of 2016, we have set our 2016 capital expenditure budget at \$15 million. This is a significant reduction from our 2015 and 2014 incurred capital expenditures of \$231 million and \$630 million, respectively. We have the flexibility to make this reduction to our 2016 capital expenditure budget because we have no long term rig commitments and no pressure from partners to drill or complete a well. Moreover, we expect our deepwater projects completed in 2015, combined with new production from our Ewing Bank 910 A-8 well will help with 2016 production levels. However, unplanned downtime, pipeline maintenance, and well performance are factors leading to lower estimated production in 2016 from 2015. We do not expect to lose drilling opportunities at this spending level and have no significant lease expiration issues in 2016. In addition, our plans include spending \$84 million in 2016 for ARO, which is an increase from \$33 million spent on ARO in 2015. We continue to closely monitor current and forecasted prices to assess if changes are needed to our plans. See *Risk Factors* under Part I, Item 1A in this Form 10-K for additional information.

Business Strategy

Our business strategy is to acquire, explore and develop oil and natural gas reserves on the Outer Continental Shelf (“OCS”), the area of our historical success and technical expertise, which we believe has yielded desirable rates of return commensurate with our perception of risks. The rapid and extended decline in crude oil, NGLs and natural gas prices that commenced in the second half of 2014 has created a great deal of uncertainty about future exploration and development. We believe this uncertainty will continue until such time as commodity prices recover, at least partially from current levels, and show signs of stability, coupled with alignment of the costs of goods and services utilized in exploration and production with prevailing commodity prices. We believe attractive acquisition opportunities will continue to become available in the Gulf of Mexico as the major integrated oil companies and other large independent oil and gas exploration and production companies continue to divest properties to focus on larger and more capital-intensive projects that better match their long-term strategic goals. Also, we expect opportunities will arise as producers seek to divest their properties for short-term cash flow needs. Our short-term focus is on conserving capital and maintaining liquidity, which may cause us to forgo these acquisition opportunities.

Our business strategy may need to be significantly altered to comply with supplementary bonding and other regulatory hurdles, which may have a material adverse impact on our liquidity. See *Risk Factors* under Part I, Item 1A and *Financial Statements and Supplementary Data – Note 20 – Subsequent Events* under Part II, Item 8 in this Form 10-K for additional information on this significant risk to our business and recent events.

We believe a portion of our Gulf of Mexico acreage has exploration potential below currently producing zones, including deep shelf reserves at subsurface depths greater than 15,000 feet. Although the cost to drill deep shelf wells is significantly higher than shallower wells, the reserve targets are typically larger, and the use of existing infrastructure, when available, can increase the economic potential of these wells. Pursuit of acquisition opportunities in the Gulf of Mexico will be dependent on a number of factors, including commodity prices, access to capital markets, supplemental bonding requirements, other regulatory challenges, possible debt covenant restrictions, ARO and other cash needs of the business. We plan to continue to evaluate opportunities to be prepared once conditions improve.

Competition

The oil and natural gas industry is highly competitive. We currently operate in the Gulf of Mexico and compete for the acquisition of oil and natural gas properties primarily on the basis of price for such properties. We compete with numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well established companies that have financial and other resources substantially greater than ours. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment and to finance acquisitions without compromising our available liquidity. For a more thorough discussion of how competition could impact our ability to successfully complete our business strategy, see *Risk Factors* under Part I, Item 1A in this Form 10-K.

Oil and Natural Gas Marketing and Delivery Commitments

We sell our crude oil, NGLs and natural gas to third-party customers. We are not dependent upon, or contractually limited to, any one customer or small group of customers. However, in 2015, approximately 50% of our sales were to Shell Trading (US) Co. and 14% to J. P. Morgan, with no other customer comprising greater than 10% of our sales. Due to the free trading nature of oil and natural gas markets in the Gulf of Mexico, we do not believe the loss of a single customer or a few customers would materially affect our ability to sell our production. For our non-operated interests in the Mississippi Canyon 782 field (Dantzer) and the Mississippi Canyon 698 field (Big Bend), we are parties to contracts that obligate the delivery of certain minimum quantities to pipeline operators, but we have the unilateral right to adjust these minimum quantities at least semi-annually. We do not have any other agreements which obligate us to deliver material quantities to third parties.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Bureau of Ocean Energy Management (“BOEM”) and the Bureau of Safety and Environmental Enforcement (“BSEE”) regulations, pursuant to the Outer Continental Shelf Lands Act (“OCSLA”), apply to our operations on Federal leases in the Gulf of Mexico.

The Federal Energy Regulatory Commission (“FERC”) regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 (“NGA”) and the Natural Gas Policy Act of 1978 (“NGPA”). In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and NGLs can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

The Federal Trade Commission, the FERC and the Commodity Futures Trading Commission (“CFTC”) hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of crude oil or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority.

These departments and agencies have authority to grant and suspend operations, and have authority to levy substantial penalties for non-compliance. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition. See *Risk Factors* under Part I, Item 1A in this Form 10-K for certain risks related to these and other regulations.

Federal leases. Most of our offshore operations are conducted on federal oil and natural gas leases. These leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed BOEM, BSEE, and other government agency regulations and orders that are subject to interpretation and change. Included in the BOEM and BSEE regulations are regulations governing the plugging and abandonment of wells located offshore and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines on the OCS (collectively, these activities are referred to as “decommissioning”).

Decommissioning and supplemental bonding requirements. The BOEM requires that lessees demonstrate financial strength and reliability according to regulations, or post supplemental bonds or other acceptable assurances that such obligations will be satisfied. Under BOEM’s Notice To Lessees #2008-N07, *Supplemental Bond Procedures* (“NTL #2008-N07”), the BOEM will waive its supplemental bonding requirements when a lessee or its guarantor meets the conditions contained in the NTL #2008-N07 that demonstrates financial strength and reliability. One of the requirements of NTL #2008-N07 requires that the estimated cumulative decommissioning liability must be less than or equal to 50% of the lessee’s most recent independently audited calculation of net worth. The significant reductions in crude oil and natural gas pricing since the middle of 2014 have adversely impacted the Company’s financial strength and have resulted in the Company no longer meeting the relevant financial strength and reliability

criteria set forth in the NTL #2008-N07. As a result, the BOEM is now demanding financial assurances to ensure our obligations will be satisfied. We have had discussions with the BOEM and surety bond providers as to the amount, terms, availability, cost and collateral requirements related to securing additional surety bonds. See *Risk Factors* under Part I, Item 1A and *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K for more discussion on decommissioning and financial assurance requirements.

In September 2015, the BOEM issued proposed guidance describing revised supplemental bonding procedures related to obligations for decommissioning activities on the federal OCS. If the proposed guidance is finalized as written, the regulations related to the NTL #2008-N07's "waiver exemption" and amount of self-insurance allowed will change. Among other things, the proposed guidance would eliminate the "waiver exemption" currently allowed by the BOEM, whereby lessees on the OCS meeting certain financial strength and reliability criteria are exempted from posting bonds or other acceptable financial assurances for such lessee's decommissioning obligations. Under the proposed guidance, qualifying operators would only be able to self-insure for an amount that is no more than 10% of their tangible net worth. In addition, the proposed guidance would implement a phase-in period for establishing compliance with supplemental bonding obligations, whereby lessees may seek compliance with its supplemental bonding requirements under a "tailored plan" that is approved by the BOEM and would require securing the supplemental bonding amount in three approximately equal installments during a one-year period from the date of the BOEM approval of the tailored plan. During December 2015, the BSEE issued a final rule requiring lessees to submit summaries of actual expenditures for decommissioning of wells, platforms, and other facilities required under the BSEE's existing regulations. The BSEE has reported that it will use this summary information to better estimate future decommissioning costs, and the BOEM may use the BSEE's estimates to set the amount of required bonds or other forms of financial security in order to minimize the government's risk of potential decommissioning liability. See *Risk Factors* under Part I, Item 1A in this Form 10-K for more discussion on decommissioning and supplemental bonding requirements.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. In recent years, the FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the results of Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. The rates for such storage and transportation services are subject to FERC ratemaking authority, and FERC exercises its authority either by applying cost-of-service principles or granting market based rates.

Similarly, the natural gas pipeline industry may also be subject to state regulations which may change from time to time. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 ("Competition Bill") and H.B. 1920 ("LUG Bill"). The Competition Bill gives the Railroad Commission of Texas ("RRC") the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Bill modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007. The RRC was subject to a sunset review during 2013 and was authorized to operate for an additional four years. Its next scheduled sunset review is in 2017.

The OCSLA, which is administered by the BOEM and the FERC, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of the FERC's principal goals in carrying out OCSLA's mandate is to increase transparency in the market to provide producers and shippers working in the OCS with greater assurance of open access service on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines. The BOEM issued a final rule, effective August 2008 that implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines on the OCS.

In December 2007, the FERC issued rules ("Order 704") requiring that any market participant, including a producer such as us, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million British thermal units ("MMBtu") during a calendar year must annually report, starting May 2009, such sales and purchases to the FERC to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state legislatures, state commissions and the courts. The natural gas industry historically has been very heavily regulated. As a result, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and the states will continue.

While these federal and state regulations for the most part affect us only indirectly, they are intended to enhance competition in natural gas markets. We cannot predict what further action the FERC, the BOEM or state regulators will take on these matters; however, we do not believe that any such action taken will affect us differently, in any material way, than other natural gas producers with which we compete.

Oil and NGLs transportation rates. Our sales of crude oil, condensate and NGLs are not currently regulated and are transacted at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. The price we receive from the sale of crude oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for crude oil, NGLs and other products are regulated by the FERC. In general, interstate crude oil, condensate and NGL pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. The FERC has established an indexing system for such transportation, which generally allows such pipelines to take an annual inflation-based rate increase.

In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes and regulations. As it relates to intrastate crude oil, condensate and natural gas liquids pipelines, state regulation is generally less rigorous than the federal regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests, which are infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way they affect other crude oil, condensate and natural gas liquids producers or marketers.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits, bonds and pollution liability insurance for the drilling of wells, regulating the location of wells, the method of drilling, casing, operating, plugging and abandoning wells, and governing the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation of oil and gas resources, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing of such wells.

Hurricanes in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past hurricanes have included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEM and the BSEE continue to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEM and the BSEE have periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures.

Environmental Regulations

General. We are subject to complex and stringent federal, state and local environmental laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and producing operations, the amounts and types of materials that may be released into the environment, the discharge and disposal of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent and address pollution, such as the closure of inactive oil and gas waste pits and the plugging of abandoned wells. The regulatory burden on the oil and gas industry increases our cost of doing business and consequently affects our profitability. The remediation, reclamation and abandonment of wells, platforms and other facilities in the Gulf of Mexico may require us to incur significant costs. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

Hazardous Substances and Wastes. The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”) imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons are subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (“RCRA”), regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and certain other wastes associated with the exploration, development or production of oil and natural gas from regulation as “hazardous waste.” Disposal of such non-hazardous oil and natural gas exploration, development and production wastes is usually regulated by state law. Other wastes handled at exploration and production sites or generated in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, various environmental groups have challenged the Environmental Protection Agency’s (“EPA”) exemption of certain oil and gas wastes from RCRA, and legislation is frequently proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from the RCRA definition of “hazardous wastes,” either of which could potentially subject such wastes to more stringent handling, disposal and cleanup requirements. Additionally, Naturally Occurring Radioactive Materials (“NORM”) may contaminate minerals extraction and processing equipment used in the oil and natural gas industry. The waste resulting from such contamination is regulated by federal and state laws. Standards have been developed for: worker protection; treatment, storage, and disposal of NORM and NORM waste; management of NORM-contaminated waste piles, containers and tanks; and limitations on the relinquishment of NORM contaminated land for unrestricted use under RCRA and state laws. We do not anticipate any material expenditures in connection with our compliance with RCRA and applicable state laws related to NORM waste.

Air Emissions and Climate Change. Air emissions from our operations are subject to the Federal Clean Air Act (“CAA”) and comparable state and local requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources.

Moreover, the U.S. Congress and the EPA, in addition to some state and regional efforts, have in recent years considered legislation or regulations to reduce emissions of greenhouse gases. These efforts have included consideration of cap-and-trade programs, carbon taxes, and greenhouse gas monitoring and reporting programs. In the absence of federal greenhouse gas limitations, the EPA has determined that greenhouse gas emissions present a danger to public health and the environment, and it has adopted regulations that, among other things, restrict emissions of greenhouse gases under existing provisions of the CAA and may require the installation of control technologies to limit emissions of greenhouse gases. These regulations would apply to any new or significantly modified facilities that we construct in the future that would otherwise emit large volumes of greenhouse gases together with other criteria pollutants. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of greenhouse gas emissions from specified offshore production sources. See *Risk Factors* under Part I, Item 1A of this Form 10-K for further discussion.

Water Discharges. The primary federal law for oil spill liability is the Oil Pollution Act (the “OPA”) which amends and augments oil spill provisions of the federal Water Pollution Control Act (the “Clean Water Act”). OPA imposes certain duties and liabilities on “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters, including the OCS or adjoining shorelines. A liable “responsible party” includes the owner or operator of an onshore facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several, strict liability, without regard to fault, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil and natural resource damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. In addition, the BOEM has finalized rules that raise OPA’s damages liability cap from \$75 million to \$134 million. OPA requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill, and to prepare and submit for approval oil spill response plans. These oil spill response plans must detail the action to be taken in the event of a spill; identify contracted spill response equipment, materials, and trained personnel; and identify the time necessary to deploy these resources in the event of a spill. In addition, OPA currently requires a minimum financial responsibility demonstration of between \$35 million and \$150 million for companies operating on the OCS. We are currently required to demonstrate, on an annual basis, that we have ready access to \$150 million that can be used to respond to an oil spill from our facilities on the OCS. As a result of the BP Deepwater Horizon incident, legislation has been proposed in Congress to increase the minimum level of financial responsibility to \$300 million or more.

The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the monitoring and discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The EPA has also adopted regulations requiring certain onshore oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our onshore facilities. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on-site storage of significant quantities of oil. We currently maintain all required discharge permits necessary to conduct our operations, and historically, our environmental compliance costs have not had a material adverse effect on our results of operations. However, there can be no assurance that such costs will not be material in the future.

Protected and Endangered Species. Executive Order 13158, issued in May 2000, directs federal agencies to safeguard existing Marine Protected Areas (“MPAs”) in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

Federal Lease Stipulations include regulations regarding the taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species). Historically, our compliance costs for the protection of marine species have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future.

Certain flora and fauna that have been officially classified as “threatened” or “endangered” are protected by the Endangered Species Act (“ESA”). This law prohibits any activities that could “take” a protected plant or animal or reduce or degrade its habitat area. We conduct operations on leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. We own a platform in the Gulf of Mexico located in a National Marine Sanctuary. As a result, we are subject to additional federal regulation, including regulations issued by the National Oceanic and Atmospheric Administration. Unique regulations related to operations in a sanctuary include prohibition of drilling activities within certain protected areas, restrictions on the types of water and other substances that may be discharged, required depths of discharge in connection with drilling and production activities and limitations on mooring of vessels.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the National Environmental Policy Act, the Coastal Zone Management Act, the Emergency Planning and Community Right-to-Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Magnuson-Stevens Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands. These and other protected areas may require certain mitigation measures to avoid harm to wildlife, and such laws and regulations may impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities.

Financial Information

We operate our business as a single segment. See *Selected Financial Data* under Part II, Item 6 and *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K for our financial information.

Seasonality

For a discussion of seasonal changes that affect our business, see *Management’s Discussion and Analysis of Financial Condition and Results of Operations – Inflation and Seasonality* under Part II, Item 7 in this Form 10-K.

Employees

As of December 31, 2015, we employed 297 people. We are not a party to any collective bargaining agreements and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at www.wtoffshore.com. These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Investor Relations, W&T Offshore, Inc., Nine Greenway Plaza, Suite 300, Houston, Texas 77046 or by calling (713) 297-8024. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC. Information on our website is not a part of this Form 10-K.

Item 1A. Risk Factors

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to us and our industry could materially impact our future performance and results of operations. We have provided below a list of known material risk factors that should be reviewed when considering buying or selling our securities. These are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Relating to Our Industry, Our Business and Our Financial Condition

Further declines in crude oil, NGLs and natural gas prices or an extended period of currently depressed prices will adversely affect our business, financial condition, cash flow, liquidity or results of operations and our ability to meet our capital expenditure obligations and financial commitments and to implement our business strategy.

The price we receive for our crude oil, NGLs and natural gas production directly affects our revenues, profitability, access to capital and future rate of growth. Crude oil, NGLs and natural gas are commodities and are subject to wide price fluctuations in response to relatively minor changes in supply and demand. The continuing depressed prices for our crude oil, NGLs and natural gas production have substantially decreased our revenues on a per unit basis and have also reduced the amount of crude oil, NGLs and natural gas that we can produce economically. Historically, the markets for crude oil, NGLs and natural gas have been volatile and will likely continue to be volatile in the future. The prices we receive for our production and the volume of our production depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for crude oil, NGLs and natural gas;
- the actions of the Organization of Petroleum Exporting Countries (“OPEC”);
- the price and quantity of imports of foreign crude oil, NGLs, natural gas and liquefied natural gas;
- acts of war, terrorism or political instability in oil producing countries;
- economic conditions;
- political conditions and events, including embargoes, affecting oil-producing activities;
- the level of global oil and natural gas exploration and production activities;
- the level of global crude oil, NGLs and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- geographic differences in pricing.

The prices of crude oil, domestic natural gas and NGLs have declined substantially since June 2014. The price of West Texas Intermediate (“WTI”) crude oil has decreased from over \$100.00 per barrel in the middle of June 2014 to below \$30.00 per barrel in January and February 2016. This decrease in prices has impacted companies throughout the oil and gas industry. Natural gas and NGLs prices have been negatively affected by excess natural gas production, high levels of stored natural gas and weather conditions affecting demand. In recent months, Henry Hub spot prices for natural gas declined below \$1.80 per Mcf in December 2015 compared to more than \$4.40 per Mcf in January 2014. Recent development activities in shale and other resource plays have the potential to yield a significant amount of natural gas and NGLs production, as well as natural gas and NGLs produced in connection with domestic oil drilling activities. The potential increases in natural gas supplies resulting from the large-scale development of these unconventional resource reserves could continue to have an adverse impact on the price of natural gas and NGLs. An environment of further or continued lower crude oil, NGLs and natural gas prices would materially and adversely affect our future business, financial condition, results of operations, liquidity, ability to finance planned capital expenditures, ability to repay any borrowing base

deficiencies under the Fifth Amended and Restated Credit Agreement, as amended, (the "Credit Agreement"), to secure supplemental bonding, to secure collateral for such bonding, if required, and to meet our other financial obligations.

The borrowing base under our Credit Agreement may be reduced by our lenders and we are required to repay borrowings that exceed the borrowing base within 90 days in three equal monthly payments.

As of the time of the filing of this report, we have substantially borrowed the entire availability on our revolving bank credit facility under the Credit Agreement. Availability of borrowings and letters of credit under the Credit Agreement is determined by establishment of a borrowing base, which is periodically redetermined during the year based on our lenders' view of crude oil, NGLs and natural gas prices and on our proved reserves. The borrowing base under the Credit Agreement was reduced during 2015, and was \$350 million as of December 31, 2015, compared to \$750 million as of December 31, 2014. The lower borrowing base was primarily due to declines in commodity prices. On February 26, 2015, we announced that we had borrowed \$340 million, which was substantially all of our available borrowings under our Credit Agreement. Our current borrowing base is in the process of being redetermined by our lenders and we expect there will be a reduction in our borrowing base. The borrowing base could be further reduced in the future as a result of the continued impact of low commodity prices, our lenders' outlook for future prices or our inability to replace reserves as a result of constrained capital spending. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base, such excess or deficiency is required to be repaid within 90 days in three equal monthly payments. In addition to the borrowing base limitation, the Credit Agreement limits our ability to incur additional indebtedness if we cannot comply with specified financial covenants and ratios.

We may not have the financial resources in the future to repay an excess or deficiency resulting from a borrowing base redetermination as required under our Credit Agreement, which could result in an event of default. Additionally, a material reduction of our current cash position could substantially limit our ability to comply with other cash needs, such as collateral needs for existing or additional supplemental surety bonds issued to BOEM for our decommissioning obligations. Further, the failure to repay an excess or deficiency that may result from a borrowing base redetermination under our Credit Agreement may result in a cross-default under our \$300 million second lien term loan (the "9.00% Term Loan") and our senior notes (the "8.50% Senior Notes"). Sustained or lower crude oil, NGLs and natural gas prices in the future would continue to adversely affect our cash flow, which could result in further reductions in our borrowing base, adversely affect prospects for alternate credit availability or affect our ability to satisfy our covenants and ratios under our Credit Agreement.

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

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or post surety bonds or other acceptable financial assurances that such decommissioning obligations will be satisfied. Prior to 2015, we were partially exempt from providing such financial assurances under our corporate structure. The significant and sustained decline in crude oil and natural gas prices, however, has resulted in the Company no longer meeting the relevant financial strength and reliability criteria for such exemptions set forth in the current regulations and procedures of the BOEM. As a result, we were notified by the BOEM in 2015 that the Company was no longer eligible for any exemption from providing financial assurances to the BOEM. Since receiving such notification, we have had discussions with the BOEM as to the amount and the properties in which the BOEM is seeking financial assurances, and with surety bond issuers as to the amount, terms, availability, cost and collateral requirements of obtaining additional surety bonds.

In February and March 2016, we received several demands from the BOEM ordering the Company to secure financial assurances in the form of additional surety bonds in the aggregate of \$260.8 million, with amounts specified with respect to certain designated leases and rights of way. The bonds are to be secured on or before March 29, 2016. As of the date of filing this Form 10-K, we have not obtained these additional supplemental bonds, or acceptable replacement collateral or other financial assurances. We may seek to utilize different forms of financial assurances, but cannot provide assurance these different forms of collateral will be acceptable to the BOEM.

We could in the future receive further demands from the BOEM for additional surety bonds covering our obligations under other leases or the BOEM could increase the amount of financial assurance required for certain leases. In addition, the BOEM has issued proposed guidance describing revised supplemental bonding procedures related to obligations for decommissioning activities on the federal OCS. Were the BOEM to finalize this proposed guidance and issue revised regulations and procedures on supplemental bonding, this could result in additional demands for surety bonds or other financial assurances.

If we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition.

We may be required to post cash collateral pursuant to our agreements with sureties under our existing bonding arrangements, which could have a material adverse effect on our liquidity and our ability to execute our capital expenditure plan, our ARO plan and comply with our existing debt instruments.

Pursuant to the terms of our agreements with various sureties under our existing bonding arrangements or under any additional bonding arrangements we may enter into, we may be required to post collateral at any time, on demand, at the surety's discretion. We have received demands for additional collateral from several of our existing sureties. The additional collateral we may be required to provide to support surety bond obligations would probably be in the form of cash or letters of credit. Given current commodity prices' effect on our creditworthiness and the willingness of the surety to post bonds without the requisite collateral, we cannot provide assurance that we will be able to satisfy collateral demands for current bonds or for additional bonds to comply with supplemental bonding requirements of the BOEM.

If we are required to provide collateral in the form of cash or letters of credit, our liquidity position will be negatively impacted and may require us to seek alternative financing. To the extent we are unable to secure adequate financing; we may be forced to reduce our capital expenditures in future years. In addition, a reduction in our liquidity may impair our ability to comply with the financial and other restrictive covenants in our indebtedness. Moreover, if we default on our Credit Agreement, then we would need a waiver or amendment from our bank lenders to prevent the acceleration of the outstanding debt under our Credit Agreement. There is no assurance that the bank lenders will waive or amend the Credit Agreement. Realization of any of these factors could have a material adverse effect on our financial condition, results of operations and cash flows.

We have a significant amount of indebtedness. Our leverage and debt service obligations may have a material adverse effect on our financial condition, results of operations and business prospects, and we may have difficulty paying our debts as they become due.

As of December 31, 2015, we had approximately \$1.2 billion in principal amount of debt and in February 2016, we borrowed \$340 million on our revolving bank credit facility, which was substantially the amount available. Our debt obligations could have important consequences. For example, they could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future working capital requirements, capital expenditures and ARO, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets;
- limit our opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt obligations or to comply with any restrictive terms of our debt obligations;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- impair our ability to obtain additional financing in the future; and
- place us at a competitive disadvantage compared to our competitors that have less debt.

Any of the above listed factors could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our ability to pay our expenses and fund our working capital needs and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as commodity prices, other economic conditions and governmental regulation. We have fully drawn on our revolving bank credit facility for liquidity, and the borrowing base under our Credit Agreement is subject to redetermination. Substantially all of our oil, NGLs and natural gas properties are pledged as collateral under our Credit Agreement and under our 9.00% Term Loan. Sustained or lower crude oil, NGLs and natural gas prices in the future will continue to adversely affect our cash flow and could result in further reductions in our borrowing base, reduce prospects for alternate credit availability, and affect our ability to satisfy the covenants and ratios under our Credit Agreement. Further asset sales may also reduce available collateral and availability under our Credit Agreement. In addition, we cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations.

If we are unable to service our indebtedness and other obligations, we may be required to restructure or refinance all or part of our existing debt, sell assets, reduce capital expenditures, borrow more money or raise equity. We may not be able to restructure or refinance our debt, reduce capital expenditures, sell assets, borrow more money or raise equity on terms acceptable to us, if at all, or such alternative strategies may yield insufficient funds to make required payments on our indebtedness. In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness is uncertain and will be affected by our future performance and events or circumstances beyond our control. Failure to comply with these covenants would result in an event of default under such indebtedness, the potential acceleration of our obligation to repay outstanding debt and the potential foreclosure on the collateral securing such debt, and could cause a cross-default under our other outstanding indebtedness. Any of the above risks could have a material adverse effect on our business, financial condition, cash flows and results of operations and could lead to a restructuring.

We may be unable to access the equity or debt capital markets to meet our obligations.

Sustained or lower crude oil, NGLs and natural gas prices will adversely affect our cash flow and may lead to further reductions in the borrowing base, which could also lead to reduced prospects for alternate credit availability. The capital markets we have historically accessed as an alternative source of equity and debt capital are currently constrained to such an extent that they are virtually inaccessible. Other capital sources may arise with significantly different terms and conditions. These limitations in the capital markets may affect our ability to grow and limit our ability to replace our reserves of oil and gas.

Our plans for growth require regular access to the capital and credit markets. If the debt or equity capital markets do not improve, or if we are unable to access alternative means of financing on acceptable terms, we may be unable to implement our drilling and development plans, make acquisitions or otherwise carry out our business strategy, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

If crude oil, NGLs and natural gas prices stay at their current levels or decrease further, we will likely be required to further write down the carrying values and/or the estimates of total reserves of our oil and natural gas properties.

Accounting rules applicable to us require that we review the carrying value of our oil and natural gas properties quarterly for possible impairment. Impairment of proved properties under our full cost oil and gas accounting method is largely driven by the present value of future net revenues of proved reserves estimated using SEC mandated 12-month unweighted first-day-of-the-month commodity prices. In addition to commodity prices, impairment assessments of proved properties include the evaluation of development plans, production data, economics and other factors. As crude oil, natural gas and NGLs prices declined in 2015, we incurred impairment charges in each quarter in 2015 totaling \$987 million for the year. Such write-downs constitute a non-cash charge to earnings. Prices in January and February of 2016 were substantially below average prices in 2015. As a result, we anticipate further material impairment charges will likely occur in 2016. You should not assume that the \$966 million present value of estimated future net revenues from our proved oil and gas reserves, PV-10, or our \$617 million PV-10 after ARO, from our proved oil and natural gas reserves shown elsewhere in this Form 10-K represents a current market value of our estimated oil and natural gas reserves. PV-10 and PV-10 after ARO are not financial measures defined under GAAP. For additional information about our proved reserves and a reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows, see *Properties – Proved Reserves* under Part I, Item 2 in this Form 10-K.

In accordance with SEC requirements, we determine the estimated discounted future net cash flows from our proved reserves and the related PV-10 and the standardized measure using the 12-month unweighted first-day-of-the-month average price for each product and estimated costs in effect on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, the average price before adjustments used in the standardized measure of discounted cash flows for December 31, 2015 for WTI crude oil was \$46.79 per barrel and the price of WTI crude oil during January and February 2016 has dropped below \$30.00 per barrel on various days during these two months. No assurance can be given that we will not experience additional ceiling test impairments in future periods, which could have a material adverse effect on our results of operations in the periods taken. As a result of lower crude oil, NGLs and natural gas prices and a corresponding reduction in our capital expenditure budget for 2016, we may also reduce our estimates of the reserve volumes that may be economically recovered, which would reduce the total value of our proved reserves. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview and Critical Accounting Policies – Impairment of oil and natural gas properties* under Part II, Item 7 and *Financial Statements and Supplementary Data – Note 1 – Significant Accounting Policies* under Part II, Item 8 in this Form 10-K for additional information on the ceiling test, including a sensitivity analysis of our December 31, 2015 ceiling test write down based on updated pricing.

We may be limited in our ability to maintain proved undeveloped reserves under current SEC guidance.

Current SEC guidance requires proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are reasonably certain to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. If current low price conditions persist, we also may be compelled to further postpone the drilling of proved undeveloped reserves until prices recover. If we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may have to write off reserves previously recognized as proved undeveloped. In addition, if we are unable to demonstrate funding sources for our development plan with reasonable certainty, we may have to write-off all or a portion of our proved undeveloped reserves.

Our proved undeveloped reserves require additional future expenditures and/or activities to convert these into producing reserves. As circumstances change, we cannot provide assurance that all future expenditures will be made and that activities will be entirely successful in converting these reserves. Additionally, we are not the operator for approximately 12% of our proved undeveloped reserves, so we may not be in a position to control the timing of all development activities. Furthermore, there can be no assurance that all of our undeveloped will ultimately be produced during the time periods we have planned, at the costs we have budgeted, or at all, which could result in the write-off of previously recognized reserves.

Relatively short production periods for our Gulf of Mexico properties subject us to high reserve replacement needs and require significant capital expenditures to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace those reserves would result in decreasing reserves, production and cash flows over time.

Unless we conduct successful development and exploration activities at sufficient levels or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves during the initial few years of production. The majority of our current production is from the Gulf of Mexico. Reserves in the Gulf of Mexico generally decline more rapidly than from reserves in many other producing regions of the United States. Our independent petroleum consultant estimates that 55% of our total proved reserves will be depleted within three years. As a result, our need to replace reserves and production from new investments is relatively greater than that of producers who recover lower percentages of their reserves over a similar time period, such as those producers who have a larger portion of their reserves in areas other than the Gulf of Mexico. We may not be able to develop, find or acquire additional reserves in sufficient quantities to sustain our current production levels or to grow production beyond current levels. In addition, due to the significant time requirements involved with exploration and development activities, particularly for wells in the deepwater or wells not located near existing infrastructure, actual oil and natural gas production from new wells may not occur, if at all, for a considerable period of time following the commencement of any particular project.

Significant capital expenditures are required to replace our reserves. If we are not able to replace reserves, we will not be able to sustain production at current levels.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful exploration, development or acquisition activities, our proved reserves and production will decline over time. Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures and acquisitions with cash on hand, cash provided by operating activities, securities offerings and bank borrowings. The capital markets we have historically accessed are currently constrained and we believe our access to capital markets remains limited at this time. We have substantially reduced our capital budget for 2016 in order to conserve capital and due to the lower returns from drilling in light of currently depressed oil and gas prices. Future cash flows are subject to a number of variables, such as the level of production from existing wells, the prices of oil, NGLs and natural gas, and our success in developing and producing new reserves. Any reductions in our capital expenditures to stay within internally generated cash flow (which could be adversely affected by declining commodity prices) and cash on hand will make replacing produced reserves more difficult. These limitations in the capital markets and our recently constrained capital budget adversely affect our ability to sustain our production at current levels, which are expected to be slightly lower in 2016, but then lower in future years due to natural production declines. We cannot be certain that financing for future capital expenditures will be available if needed, and to the extent required, on acceptable terms. For additional financing risks, see “– Risks Related to Financings.”

Additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration and oil spill-response plans, and other related restrictions arising after the Deepwater Horizon incident in the Gulf of Mexico may have a material adverse effect on our business, financial condition, or results of operations.

In response to the Deepwater Horizon incident in the Gulf of Mexico in April 2010, the federal government, acting through the U.S. Department of the Interior and its implementing agencies that have since evolved into the present day BOEM and BSEE, have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. These governmental agencies have implemented and enforced new rules, Notices to Lessees and Operators and temporary drilling moratoria that impose safety and operational performance measures on exploration, development and production operators in the Gulf of Mexico or otherwise resulted in a temporary cessation of drilling activities. Compliance with these added and more stringent regulatory restrictions in addition to any uncertainties or inconsistencies in current decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development and oil spill-response plans could adversely affect or delay new drilling and ongoing development efforts. Moreover, these governmental agencies are continuing to evaluate aspects of safety and operational performance in the Gulf of Mexico and, as a result, developing and implementing new, more restrictive requirements.

Among other adverse impacts, these additional measures could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding requirements and incurrence of associated added costs, limit operational activities in certain areas, or cause us to incur penalties or shut-in production at one or more of our facilities. Since the adoption of these new regulatory requirements, the BOEM has been taking longer to review and approve permits for new wells than was common prior to the Deepwater Horizon incident. These new requirements also increase the cost of preparing permit applications and increase the cost of each new well, particularly for wells drilled in the deepwater on the OCS. Additional federal action is likely. For example, in April 2015, BSEE released a proposed rule containing more stringent standards relating to well control equipment used in connection with offshore well drilling operations. The proposed standards focus on blowout preventers, along with well design, well control, casing, cementing, real-time well monitoring, and subsea containment requirements. If similar material spill incidents were to occur in the future, the United States or other countries could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations.

Further, the deepwater areas of the Gulf of Mexico (as well as international deepwater locations) lack the degree of physical and oilfield service infrastructure present in shallower waters. Therefore, despite our oil spill-response capabilities, it may be difficult for us to quickly or effectively execute any contingency plans related to future events similar to the Deepwater Horizon incident. The matters described above, individually or in the aggregate, could have a material adverse effect on our business, prospects, results of operations, financial condition and liquidity.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

We could be exposed to uninsured losses in the future. The occurrence of a significant accident or other event not covered in whole or in part by our insurance could have a material adverse impact on our financial condition and operations. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. In May and June 2015, we renewed our insurance policies covering well control, hurricane damage, general liability and pollution. These policies reduce, but do not totally mitigate, our risk as we are exposed to amounts for retention and co-insurance, limits on coverage and some events that are not insured. These policies expire in May and June 2016. We also have other smaller per-occurrence retention amounts for various other events. In addition, pollution and environmental risks are generally not fully insurable, as gradual seepage and pollution are not covered under our policies. Because third-party drilling contractors are used to drill our wells, we may not realize the full benefit of workmen's compensation laws in dealing with their employees.

OPA requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. We are currently required to demonstrate, on an annual basis, that we have ready access to \$150 million that can be used to respond to an oil spill from our facilities on the OCS. As a result of the BP Deepwater Horizon incident, legislation has been proposed in Congress from time to time to increase the minimum level of financial responsibility to \$300 million or more. If OPA is amended to increase the minimum level of financial responsibility to \$300 million, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. We cannot predict at this time whether OPA will be amended, or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if an oil discharge or substantial threat of discharge were to occur, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Hurricane Remediation, Insurance Claims and Insurance Coverage* under Part II, Item 7 in this Form 10-K for additional information on insurance coverage.

Insurance for well control and hurricane damage may become significantly more expensive for less coverage, and some losses currently covered by insurance may not be covered in the future.

In the past, hurricanes in the Gulf of Mexico have caused catastrophic losses and property damage. Well control insurance coverage has become more limited at times and the cost of such coverage has become both more costly and more volatile at times. The insurance market may change dramatically in the future due to the major oil spills, such as BP's Macondo well in the deepwater Gulf of Mexico occurring in 2010. As of December 31, 2015, virtually all of our PV-10 value of proved reserves is on platforms that are covered under our current insurance policies for named windstorm damage, but these policies only cover a portion of the risk.

In the future, our insurers may not continue to offer us the type and level of our current coverage, 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. 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 insurance companies will not pay our claims. The occurrence of any or all of these possibilities could have a material adverse effect on our financial condition and results of operations.

Commodity derivative positions may limit our potential gains.

In order to manage our exposure to price risk in the marketing of our oil and natural gas, we periodically enter into oil and natural gas price commodity derivative positions with respect to a portion of our expected production. While these commodity derivative positions are intended to reduce the effects of volatile crude oil and natural gas prices, they may also limit future income if crude oil and natural gas prices were to rise substantially over the price established by such positions. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery points assumed in the hedge arrangements; or
- the counterparties to the derivative contracts fail to perform under the terms of the contracts.

See *Financial Statements and Supplementary Data— Note 6 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information on derivative transactions.

Competition for oil and natural gas properties and prospects is intense; some of our competitors have larger financial, technical and personnel resources that may give them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil, NGLs and natural gas and securing trained personnel. Many of our competitors have financial resources that allow them to obtain substantially greater technical expertise and personnel than we have. We actively compete with other companies in our industry when acquiring new leases or oil and natural gas properties. For example, new leases acquired from the BOEM are acquired through a “sealed bid” process and are generally awarded to the highest bidder. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our competitors may also be able to pay more for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay or finance. On the acquisition opportunities made available to us, we compete with other companies in our industry for such properties through a private bidding process, direct negotiations or some combination thereof. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties that generate acceptable rates of return under forecast future prices and costs. Our competitors may have significantly more capital resources and less expensive sources of capital for these prospects. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the divesting practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors we cannot control or influence. Additional requirements and limitations recently imposed on us and our ability to finance such acquisitions may put us at a competitive disadvantage for acquiring properties. These risks are described above in the risk factor entitled: *We may be unable to provide the financial assurances demanded by the BOEM to cover our lease decommissioning obligations in the amounts and under the time periods required by the BOEM. If extensions and modifications to the BOEM’s current or future demands are needed and cannot be obtained, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.*

We conduct exploration, development and production operations on the deep shelf and in the deepwater of the Gulf of Mexico, which presents unique operating risks.

The deep shelf and the deepwater of the Gulf of Mexico are areas that have had less drilling activity due, in part, to their geological complexity, depth and higher cost to drill and ultimately develop. There are additional risks associated with deep shelf and deepwater drilling that could result in substantial cost overruns and/or result in uneconomic projects or wells. Deeper targets are more difficult to interpret with traditional seismic processing. Moreover, drilling costs and the risk of mechanical failure are significantly higher because of the additional depth and adverse conditions, such as high temperature and pressure. For example, the drilling of deepwater wells requires specific types of rigs with significantly higher day rates, as compared to the rigs used in shallower water. Deepwater wells have greater mechanical risks because the wellhead equipment is installed on the sea floor. Deepwater development costs can be significantly higher than development costs for wells drilled on the conventional shelf because deepwater drilling requires

larger installation equipment, sophisticated sea floor production handling equipment, expensive state-of-the-art platforms and infrastructure investments. Deep shelf development can also be more expensive than conventional shelf projects because deep shelf development requires more drilling days and higher drilling and service costs due to extreme pressure and temperatures associated with greater depths. Accordingly, we cannot assure you that our oil and natural gas exploration activities in the deep shelf, the deepwater and elsewhere will be commercially successful.

Our estimates of future asset retirement obligations may vary significantly from period to period and are especially significant because our operations are concentrated in the Gulf of Mexico.

We are required to record a liability for the present value of our ARO to plug and abandon inactive non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the Gulf of Mexico is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or such requirements may be interpreted more restrictively, and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, we may make significant increases or decreases to our estimated ARO in future periods. For example, because we operate in the Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimate of future ARO could differ dramatically from what we may ultimately incur as a result of platform damage.

During 2015, the additional bonding requirements under the BOEM's existing NTL #2008-N07 have increased the costs of our operations and availability of such bonds has been decreasing rapidly due to the decreases in commodity prices. In addition, the demand received from the BOEM in February 2016 will increase our costs and impact our liquidity in the future. The BOEM's proposed guidance or any issuance of a revised NTL that will replace the existing NTL #2008-N07 on supplemental bonding is likely to further increase such costs and decrease such bond availability. In addition, increased demand for salvage contractors and equipment could result in increased costs for plugging and abandonment operations. These items have, and may, further increase our costs and may impact our liquidity adversely.

We may be obligated to pay costs related to other companies that have filed for bankruptcy or have indicated they are unable to pay their share of costs in joint ownership arrangements.

In our contractual arrangements of joint ownership of oil and gas interests with other companies, we are obligated to pay our share of operating, capital and decommission costs, and have the right to a share of revenues after royalties and certain other cash inflows. If one of the companies in the arrangement is unable to pay its agreed upon share of costs, generally the other companies in the arrangement are obligated to pay the non-paying company's obligations. Under joint operating agreements among working interest owners, the non-paying company would typically lose the right to future revenues, which would be distributed to the other companies in the arrangement. If future revenues are insufficient to defray these additional costs, especially in case where the well has stopped producing and is being decommissioned, we would be obligated to pay certain costs. In addition, the liability to the U.S. Government for obligations of lessees under federal oil and gas leases, including obligations for decommissioning costs, is generally joint and several among the various co-owners of the lease, which means that any single owner may be liable to the U.S. Government for the full amount of all lessees' obligations under the lease. In certain circumstances, we also could be liable for decommissioning liabilities on federal oil and gas leases that we previously owned and the assignee is bankrupt or unable to pay its decommissioning costs. For example, we have received a demand for payment of such costs related to property interests that were sold several years ago. These indirect obligations would affect our costs, operating profits and cash flows negatively and could be substantial.

We may not be in a position to control the timing of development efforts, associated costs or the rate of production of the reserves from our non-operated properties.

As we carry out our drilling program, we may not serve as operator of all planned wells. We have limited ability to exercise influence over the operations of some non-operated properties and their associated costs. Our dependence on the operator and other working interest owners and our limited ability to influence operations and associated costs of properties operated by others could prevent the realization of anticipated results in drilling or acquisition activities. The success and timing of exploration and development activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells and such participants' financial resources;
- selection of technology; and
- the rate of production of the reserves.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our development activities may be unsuccessful for many reasons, including adverse weather conditions, cost overruns, equipment shortages, geological issues and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not assure us that we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells hinder our efforts to replace reserves.

Our oil and natural gas exploration and production activities, including well stimulation and completion activities, involve a variety of operating risks, including:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as tropical storms, hurricanes and other adverse weather conditions;
- inability to obtain insurance at reasonable rates;
- failure to receive payment on insurance claims in a timely manner, or for the full amount claimed;
- pipe, cement, subsea well or pipeline failures;
- casing collapses or failures;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations or rock compaction; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, encountering NORM, and discharges of brine, well stimulation and completion fluids, toxic gases, or other pollutants into the surface and subsurface environment.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations;
- repairs required to resume operations; and
- loss of reserves.

Offshore operations are also subject to a variety of operating risks related to the marine environment, such as capsizing, collisions and damage or loss from tropical storms, hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. Companies that incur environmental liabilities frequently also confront third-party claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site. Despite the “petroleum exclusion” of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. We may have liability for releases of hazardous substances at our properties by prior owners, operators, other third parties, or at properties we have sold. As a result, we could incur substantial liabilities that could reduce or eliminate funds available for exploration, development and acquisitions or result in the loss of property and equipment.

The geographic concentration of our properties in the Gulf of Mexico subjects us to an increased risk of loss of revenues or curtailment of production from factors specifically affecting the Gulf of Mexico.

The geographic concentration of our properties along the U.S. Gulf Coast and adjacent waters on and beyond the OCS means that some or all of our properties could be affected by the same event should the Gulf of Mexico experience:

- severe weather, including tropical storms and hurricanes;
- delays or decreases in production, the availability of equipment, facilities or services;
- changes in the status of pipelines that we depend on for transportation of our production to the marketplace;
- delays or decreases in the availability of capacity to transport, gather or process production; and
- changes in the regulatory environment.

Because a majority of our properties could experience the same conditions at the same time, these conditions could have a greater impact on our results of operations than they might have on other operators who have properties over a wider geographic area. For example, net production of approximately 8.7 Bcfe was deferred as a result of damage caused primarily by Hurricane Ike in 2009 and Hurricane Isaac caused net production deferral of approximately 2.9 Bcfe in 2012. In 2015 and 2014, we experienced production deferrals of similar levels due to other events, such as pipeline shut-ins.

Properties that we acquire may not produce as projected and we may be unable to immediately identify liabilities associated with these properties or obtain protection from sellers against them.

Our business strategy includes growing by making acquisitions, which may include acquisitions of exploration and production companies, producing properties and undeveloped leasehold interests. Our acquisition of oil and natural gas properties requires assessments of many factors that are inherently inexact and may be inaccurate, including the following:

- acceptable prices for available properties;
- amounts of recoverable reserves;
- estimates of future crude oil, NGLs and natural gas prices;
- estimates of future exploratory, development and operating costs;
- estimates of the costs and timing of plugging and abandonment; and
- estimates of potential environmental and other liabilities.

Our assessment of the acquired properties will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to fully assess their capabilities and deficiencies. In the course of our due diligence, we have historically not physically inspected every well, platform or pipeline. Even if we had physically inspected each of these, our inspections may not have revealed structural and environmental problems, such as pipeline corrosion, well bore issues or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities associated with such risks. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We may encounter difficulties integrating the operations of newly acquired oil and natural gas properties or businesses.

Increasing our reserve base through acquisitions is an important part of our business strategy. We may encounter difficulties integrating the operations of newly acquired oil and natural gas properties or businesses. In particular, we may face significant challenges in consolidating functions and integrating procedures, personnel and operations in an effective manner. The failure to successfully integrate such properties or businesses into our business may adversely affect our business and results of operations. Any acquisition we make may involve numerous risks, including:

- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets before our acquisition;
- our lack of drilling history in the geographic areas in which the acquired business operates;
- customer or key employee loss from the acquired business;
- increased administration of new personnel;
- additional costs due to increased scope and complexity of our operations; and
- potential disruption of our ongoing business.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. To the extent that we acquire properties substantially different from the properties in our primary operating region or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as with acquisitions within our primary operating region. We may not be successful in addressing these risks or any other problems encountered in connection with any acquisition we may make.

Estimates of our proved reserves depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in the estimates or underlying assumptions will materially affect the quantities of and present value of future net revenues from our proved reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of our reserves at December 31, 2015. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Oil and natural gas reserve quantities*, under Part II, Item 7 for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in *Business* under Part I, Item 1, *Properties* under Part I, Item 2 and *Financial Statements and Supplementary Data – Note 21 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K.

In order to prepare our year-end reserve estimates, our independent petroleum consultant projected our production rates and timing of development expenditures. Our independent petroleum consultant also analyzed available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary and may not be under our control. The process also requires economic assumptions about matters such as crude oil and natural gas prices, operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, our independent petroleum consultant may adjust estimates of proved reserves to reflect production history, drilling results, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved oil and natural gas reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month unweighted first-day-of-the-month average price for each product and costs in effect on the date of the estimate, which prices are not reflective of the lower prices realized in December 2015, January 2016 and February 2016. Actual future prices and costs may differ materially from those used in the present value estimate.

Prospects that we decide to drill may not yield oil or natural gas in commercial quantities or quantities sufficient to meet our targeted rate of return.

A prospect is an area in which we own an interest, could acquire an interest or have operating rights, and have what our geoscientists believe, based on available seismic and geological information, to be indications of economic accumulations of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure that the analysis we perform using data from other wells, more fully explored prospects and/or producing fields will accurately predict the characteristics and potential reserves associated with our drilling prospects. The recent downturn in crude oil, NGLs and natural gas pricing will also significantly impact the projected rates of return of our projects without the assurance of significant reductions in costs of drilling and development. To the extent we drill additional wells in the deepwater and/or on the deep shelf, our drilling activities could become more expensive. In addition, the geological complexity of deepwater, deep shelf and various onshore formations may make it more difficult for us to sustain our historical rates of drilling success. As a result, we can offer no assurance that we will find commercial quantities of oil and natural gas and, therefore, we can offer no assurance that we will achieve positive rates of return on our investments.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities, which in most cases are owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells because of a reduction in demand for our production or because of inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market. We have, in the past, been required to shut in wells when hurricanes have caused or threatened damage to pipelines and gathering stations. For example, in September 2008, as a result of Hurricane Ike, two of our operated platforms and eight non-operated platforms were toppled and a number of platforms, third-party pipelines and processing facilities upon which we depend to deliver our production to the marketplace were damaged. In 2012, under threat of Hurricane Isaac, we shut in most of our offshore production for a period of 10 to 25 days. Similar shut-ins of lower magnitude occurred in 2013.

In some cases, our wells are tied back to platforms owned by parties who do not have an economic interest in our wells and we cannot be assured that such parties will continue to process our oil and natural gas.

Currently, a portion of our oil and natural gas is processed for sale on platforms owned by parties with no economic interest in our wells and no other processing facilities would be available to process such oil and natural gas without significant investment by us. In addition, third-party platforms could be damaged or destroyed by hurricanes which could reduce or eliminate our ability to market our production. As of December 31, 2015, 13 fields, accounting for approximately 12.8 Bcfe (or 13%) of our 2015 production, are tied back to separate, third-party owned platforms. There can be no assurance that the owners of such platforms will continue to process our oil and natural gas production. If any of these platform operators ceases to operate their processing equipment, we may be required to shut in the associated wells, construct additional facilities or assume additional liability to re-establish production.

If third-party pipelines connected to our facilities become partially or fully unavailable to transport our crude oil and natural gas or if the prices charged by these third-party pipelines increase, our revenues or costs could be adversely affected.

We depend upon third-party pipelines that provide delivery options from our facilities. Because we do not own or operate these pipelines, their continued operation is not within our control. If any of these third-party pipelines become partially or fully unavailable to transport crude oil and natural gas, or if the gas quality specification for the natural gas pipelines changes so as to restrict our ability to transport natural gas on those pipelines, our revenues could be adversely affected. For example, in 2013, various pipelines were shut down causing production deferral of approximately 6.3 Bcfe. Our Mississippi Canyon 506 field (Wrigley) was the field most significantly affected by the shutdowns, as it was shut down for all of 2013 and more than half of 2014.

Certain third-party pipelines have submitted or have made plans to submit requests to increase the fees they charge us to use these pipelines. These increased fees could adversely impact our revenues or operating costs, either of which would adversely impact our operating profits, cash flows and reserves.

We are subject to numerous laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration, development, production and transportation of crude oil and natural gas and operational safety. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations or our failure to comply with such legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental regulations, such as:

- land use restrictions;
- lease permit restrictions;

- drilling bonds and other financial responsibility requirements, such as plugging and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- operational reporting;
- reporting of natural gas sales for resale; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well site reclamation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. It is also possible that a portion of our oil and natural gas properties could be subject to eminent domain proceedings or other government takings for which we may not be adequately compensated. See *Business – Regulation* under Part I, Item 1 in this Form 10-K for a more detailed explanation of regulations impacting our business.

Our operations may incur substantial liabilities to comply with environmental laws, endangered species laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit exploration or drilling activities on certain lands lying within wilderness, wetlands and other protected areas or that may affect certain wildlife, including marine mammals; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- loss of our leases;
- incurrence of investigatory or remedial obligations; and
- the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the

release or contamination and regardless of whether our operations met previous standards in the industry at the time they were conducted. Our permits require that we report any incidents that cause or could cause environmental damages. Examples of recent proposed and final regulations include the following:

- *Ground-Level Ozone Standards.* In October 2015, the EPA issued a final rule under the Clean Air Act lowering the National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone from 75 to 70 parts per billion. Certain areas of the country currently in compliance with the ground-level ozone NAAQS standard may be reclassified as non-attainment and such reclassification may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant.
- *Reduction of Methane Emissions by the Oil and Gas Industry.* In August 2015, the EPA proposed rules that will establish emission standards for methane from certain new and modified oil and natural gas production, processing, and transmission facilities as part of the Obama Administration’s goal to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 emission levels by 2025. The EPA’s proposed rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, fugitive emissions from well sites and compressors, and equipment leaks at natural gas processing plants and pneumatic pumps. The EPA is expected to finalize these rules in 2016.
- *Endangered Species.* We conduct operations on leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. Presence of these species in areas where we operate could cause increased costs arising from species protection measures, or could result in limitations or prohibitions on our exploration and production activities.

These and other regulatory changes could significantly increase our capital expenditures and operating costs or could result in delays to or limitations on our exploration and production activities, which could have an adverse effect on our financial condition, results of operations, or cash flows. See *Business – Regulation* under Part I, Item 1 in this Form 10-K for a more detailed description of our environmental and endangered species regulations.

Should we fail to comply with all applicable FERC and CFTC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EP Act of 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for current violations of up to \$1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Under the Commodity Exchange Act and regulations promulgated thereunder by the CFTC, the CFTC has adopted anti-market manipulation rules relating to the prices or futures of commodities. Additional rules and legislation pertaining to those and other matters may be considered or adopted by Congress, the FERC, or the CFTC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability. See *Business – Regulation* under Part I, Item 1 in this Form 10-K for further description of our regulations.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

The EPA has determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climatic changes. Based on its findings, the EPA began adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which imposes preconstruction and operating permit requirements of certain large stationary sources. The EPA also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified

large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis. In December 2015, the EPA finalized rules that added new sources to the scope of the greenhouse gases monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. The Obama Administration announced in January 2015 its goal to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 emission levels by 2025, and in August 2015, the EPA announced proposed rules that would establish new air emission controls for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The EPA's proposed rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. Compliance with these proposed rules will require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks, and the increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance. These new and proposed rules could result in increased compliance costs on our operations.

The United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases. In addition, many of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. Our offshore operations are particularly at risk from severe climatic events. If any such climate effects were to occur, they could have an adverse effect on our business, financial condition and results of operations. See – *Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.* – under this Item 1A.

The enactment of derivatives legislation and regulation could have an adverse effect on our ability to use derivative instruments to reduce the negative effect of commodity price changes, interest rate and other risks associated with our business.

In July 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "DF Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The DF Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the DF Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us in connection with covered derivatives activities to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although the Company expects to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that the Company uses for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margins. Posting of collateral could impact liquidity and reduce cash available to the Company for its needs. The DF Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The full impact of the DF Act and related regulatory requirements upon the Company's business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The DF Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, increase our exposure to less creditworthy counterparties or reduce liquidity. If we reduce our use of derivatives as a result of the DF Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Finally, the DF Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the DF Act is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

We own a platform in a highly regulated National Marine Sanctuary, which increases our compliance costs and subjects us to risk of significant fines and penalties if we do not maintain rigorous compliance.

We own a platform located in a National Marine Sanctuary in the Gulf of Mexico that is subject to special federal laws and regulations. This production platform is not producing and will be plugged, abandoned and remediated according to regulations. Unique regulations related to operations in the Sanctuary include, among other things, prohibition of drilling activities within certain protected areas, restrictions on substances that may be discharged, depths of discharge in connection with drilling and production activities and limitations on mooring of vessels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief, including cessation of production from wells associated with this platform.

Our operations could be adversely impacted by security breaches, including cyber-security breaches, which could affect our production of oil and natural gas or could affect other parts of our business.

We rely on our information technology infrastructure and management information systems to operate and record aspects of our business. Although we take measures to protect against cybersecurity risks, including unauthorized access to our confidential and proprietary information, our security measures may not be able to detect or prevent every attempted breach. Similar to other companies, we have experienced cyber-attacks, although we have not suffered any material losses related to such attacks. Security breaches include, among other things, illegal hacking, computer viruses, or acts of vandalism or terrorism. A breach could result in an interruption in our operations, unauthorized publication of our confidential business or proprietary information, unauthorized release of customer or employee data, violation of privacy or other laws and exposure to litigation. Any of these security breaches could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

The loss of members of our senior management could adversely affect us.

To a large extent, we depend on the services of our senior management. The loss of the services of any of our senior management, including Tracy W. Krohn, our Founder, Chairman and Chief Executive Officer; Jamie L. Vazquez, our President; John D. Gibbons, our Senior Vice President and Chief Financial Officer; Thomas P. Murphy, our Senior Vice President and Chief Operations Officer; Stephen L. Schroeder, our Senior Vice President and Chief Technical Officer; and Thomas F. Getten, our Vice President, General Counsel and Corporate Secretary, could have a negative impact on our operations. We do not maintain or plan to obtain for the benefit of the Company any insurance against the loss of any of these individuals. See *Executive Officers of the Registrant* under Part I following Item 3 in this Form 10-K for more information regarding our senior management team.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Moreover, President Obama has proposed, as part of the Budget of the United States Government for Fiscal Year 2017, to impose an “oil fee” of \$10.25 on a per barrel equivalent of crude oil. This fee would be collected on domestically produced and imported petroleum products. The fee would be phased in evenly over five years, beginning October 1, 2016 if enacted as proposed.

It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and production, and any such change could have a negative effect on the results of our operations.

Counterparty credit risk may negatively impact the conversion of our accounts receivables to cash.

Substantially all of our accounts receivable result from crude oil, NGLs and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by any adverse changes in economic or other conditions. In recent years, market conditions resulting in downgrades to credit ratings of energy merchants affected the liquidity of several of our purchasers.

Risks Related to Our Principal Shareholder, Tracy W. Krohn

We will be controlled by Tracy W. Krohn as long as he owns a majority of our outstanding common stock, and other shareholders will be unable to affect the outcome of shareholder voting during that time. This control may adversely affect the value of our common stock and inhibit a change of control.

Tracy W. Krohn owns and controls 40,049,164 shares of our common stock, representing approximately 52.3% of our voting interests as of February 15, 2016. As a result, Mr. Krohn has the ability to control the outcome of matters that require a simple majority of shareholders for approval. Mr. Krohn, subject to any duty owed to our minority shareholders under Texas law, is able to control all matters affecting us, including:

- the composition of our board of directors and, through it, any determination with respect to our business direction and policies, including the appointment and removal of officers;
- the determination of incentive compensation, which may affect our ability to retain key employees;
- any determinations with respect to mergers or other business combinations;
- our acquisition or disposition of assets;
- our financing decisions and our capital raising activities;
- our payment of dividends on our common stock, subject to the restrictions in our Credit Agreement and indentures; and
- amendments to our amended and restated articles of incorporation or bylaws.

Mr. Krohn is generally not prohibited from selling a controlling interest in us to a third party. In addition, his concentrated control could discourage others from initiating any potential merger, takeover or other change of control transaction that might be beneficial to our business or shareholders. As a result, the market price of our common stock could be adversely affected.

Due to Mr. Krohn's ownership and control, we are exempted from many New York Stock Exchange ("NYSE") corporate governance rules, and, as a result, our other shareholders may not have the protections set forth in those rules, particularly in the event of conflicts of interest with Mr. Krohn.

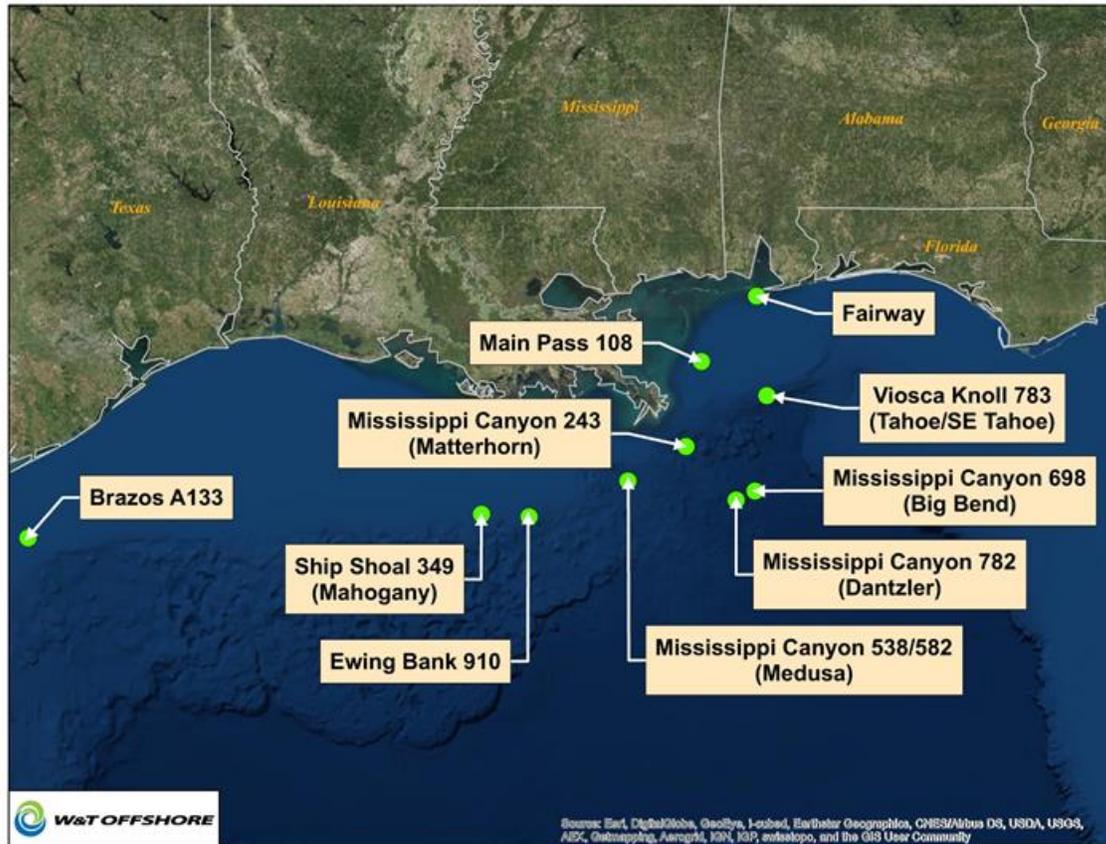
Mr. Krohn owns a majority of our common stock, and, therefore, we are a "controlled company" within the meaning of the rules of the NYSE. As such, we are not required to comply with certain corporate governance rules of the NYSE that would otherwise apply to us as a listed company on that exchange. These rules are generally intended to increase the likelihood that boards will make decisions in the best interests of shareholders. Should the interests of Mr. Krohn differ from those of other shareholders, the other shareholders will not be afforded the protections of having all of the other directors on the board being independent from our principal shareholder.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our fields are located in federal and state waters in the Gulf of Mexico. The fields are found in water depths ranging from less than 10 feet up to 7,200 feet. The reservoirs in our offshore fields are generally characterized as having high porosity and permeability, which typically results in high production rates. The following map provides the locations of our 10 largest fields as of December 31, 2015, based on quantities of proved reserves on an energy equivalent basis. At December 31, 2015, these fields accounted for approximately 83% of our proved reserves.



The following table provides information for our 10 largest fields in descending order of proved net reserves as of December 31, 2015, based on quantities on an energy equivalent basis. Deepwater refers to acreage in over 500 feet of water. Our interests in several of our offshore fields are owned by our wholly-owned subsidiary, W & T Energy VI, LLC. Unless indicated otherwise, “drilling” or “drilled” in the field descriptions below refers to when the drilling reached target depth, as this measurement usually has a higher correlation to changes in proved reserves compared to using the SEC’s definition for completion.

Field Name	Field Category	Percent Oil and NGLs of Net Reserves (1)	2015 Average Daily Equivalent Sales Rate (Boe/d) (1)		2015 Average Daily Equivalent Sales Rate (Mcf/d) (1)	
			Gross	Net	Gross	Net
Ship Shoal 349 (Mahogany)	Shelf	80 %	9,985	8,320	59,908	49,922
Fairway	Shelf	22 %	6,241	4,680	37,444	28,083
Miss. Canyon 243 (Matterhorn)	Deepwater	81 %	3,754	3,754	22,522	22,522
Viosca Knoll 783 (Tahoe/SE Tahoe)	Deepwater	25 %	5,400	3,915	32,397	23,491
Miss. Canyon 782 (Dantzler) (2)	Deepwater	73 %	19,447	3,160	116,681	18,959
Main Pass 108	Shelf	19 %	2,974	2,337	17,845	14,023
Brazos A133	Shelf	1 %	3,691	1,538	22,146	9,228
Ewing Bank 910	Deepwater	54 %	1,407	623	8,442	3,735
Miss. Canyon 698 (Big Bend) (2)	Deepwater	92 %	20,467	3,582	122,802	21,493
Miss. Canyon 538/582 (Medusa)	Deepwater	89 %	10,662	1,599	63,974	9,596

- (1) The conversions to barrels of oil equivalent and cubic feet equivalent were determined using the energy equivalency ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price on an equivalent basis for oil, NGLs and natural gas may differ significantly.
- (2) Production in these fields began in the 4th quarter of 2015. Production for November and December 2015 was used to compute daily sales rates.

Volume measurements:

Boe/d – barrel of oil equivalent per day

Mcf/d – Thousand cubic feet of gas equivalent per day

Our Fields

On December 31, 2015, we had two fields of major significance (which we define as having year-end proved reserves of 15% or more of the Company’s total proved reserves, calculated on an energy equivalent basis). The first field is the Ship Shoal 349 field (Mahogany) located on the conventional shelf in the Gulf of Mexico. The second field is the Fairway Field, located in the Mobile Bay area of Alabama, and the associated Yellowhammer gas processing plant located in Alabama. The following are descriptions of these fields.

Ship Shoal 349 Field (Mahogany).

Ship Shoal 349 field is located off the coast of Louisiana, approximately 235 miles southeast of New Orleans, in 375 feet of water. The field area covers Ship Shoal blocks 349 and 359, with a single production platform on Ship Shoal block 349. Phillips Petroleum Company discovered the field in 1993. We initially acquired a 25% working interest in the field from BP Amoco in 1999. In 2003, we acquired an additional 34% working interest through a transaction with ConocoPhillips that increased our working interest to approximately 59%, and we became the operator of the field in December 2004. In early 2008, we acquired the remaining working interest from Apache Corporation and we now own a 100% working interest in this field. Cumulative field production through 2015 is approximately 41.1 MMBoe gross (246.4 Bcfe gross). This field is a sub-salt development with eight productive horizons below salt at depths up to 17,000 feet. In 2010, we developed a reservoir simulation model to determine the most optimal future development plan (the "2010 Development Plan"). As a result, in 2011, we drilled and completed one development well and one exploration well. In 2012, two additional wells were sidetracked, one well was drilled and completed, and another well was drilled to target depth. In 2013, the well reaching target depth in 2012 was completed, one well was drilled and completed and we had one well being drilled. In 2014, the well being drilled in 2013 was completed and we drilled and completed another well. A third well was spud at year end 2014 and, in January 2015, drilling on this well was suspended at an intermediate casing point pending higher crude oil prices. All of the wells drilled under the 2010 Development Plan have been successful. Total proved reserves associated with our interest in this field were 22.3 MMBoe (134.1 Bcfe) at December 31, 2015, 18.8 MMBoe (112.9 Bcfe) at December 31, 2014, and 22.9 MMBoe (137.7 Bcfe) at December 31, 2013.

The following presents our produced oil, NGLs and natural gas volumes (net to our interests) from the Ship Shoal 349 field over the past three years.

	Year Ended December 31,		
	2015	2014	2013
Net Sales:			
Oil (MBbls)	2,313	2,020	1,943
NGLs (MBbls)	97	104	90
Natural gas (MMcf)	3,764	3,433	3,328
Total oil equivalent (MBoe)	3,037	2,697	2,589
Total natural gas equivalents (MMcfe)	18,221	16,181	15,533
Average daily equivalent sales (Boe/day)	8,320	7,388	7,093
Average daily equivalent sales (Mcf/day)	49,922	44,330	42,556
Average realized sales prices:			
Oil (\$/Bbl)	\$ 42.73	\$ 87.21	\$ 98.69
NGLs (\$/Bbl)	21.27	46.46	43.24
Natural gas (\$/Mcf)	2.86	4.40	3.72
Oil equivalent (\$/Boe)	36.77	72.73	80.39
Natural gas equivalent (\$/Mcfe)	6.13	12.12	13.40
Average production costs: (1)			
Oil equivalent (\$/Boe)	\$ 3.30	\$ 4.12	\$ 3.68
Natural gas equivalent (\$/Mcfe)	0.55	0.69	0.61

(1) Includes lease operating expenses and gathering and transportation costs.

Volume measurements:

Boe – barrel of oil equivalent

MBbls – thousand barrels for crude oil, condensate or NGLs

MBoe – thousand barrels of oil equivalent

Mcf – thousand cubic feet

MMcf – million cubic feet

MMcfe – million cubic feet of gas equivalent

Fairway Field.

The Fairway Field is comprised of Mobile Bay Area blocks 113 (Alabama State Lease #0531) and 132 (Alabama State Lease #0532) and located in 25 feet of water, approximately 35 miles south of Mobile, Alabama. We acquired our 64.3% working interest, along with operatorship in the Fairway Field and the associated Yellowhammer gas processing plant, from Shell Offshore, Inc. (“Shell”) in August 2011 and acquired the remaining working interest of 35.7% in September 2014. The field was discovered in 1985 with Well 113 #1 (now called JA). Development drilling began in 1990 and was completed in 1991 with the addition of four wells, each drilled from separate surface locations. The five producing wells came on line in late 1991. As of December 31, 2015, six wells have been drilled, one of which was a replacement well. Cumulative field production through 2015 is approximately 127.8 MMBoe gross (766.6 Bcfe gross). This field is a Norphlet sand dune trend development with one producing horizon at an approximate depth of 21,300 feet. Total proved reserves associated with our interest in this field were 14.0 MMBoe (83.7 Bcfe) at December 31, 2015, 14.6 MMBoe (87.8) at December 31, 2014, and 9.3 MMBoe (55.7 Bcfe) at December 31, 2013.

	Year Ended December 31,		
	2015	2014	2013
Net Sales:			
Oil (MBbls)	10	7	5
NGLs (MBbls)	319	415	288
Natural gas (MMcf)	8,277	6,899	4,614
Total oil equivalent (MBoe)	1,708	1,571	1,062
Total natural gas equivalents (MMcfe)	10,250	9,428	6,373
Average daily equivalent sales (Boe/day)	4,680	4,305	2,910
Average daily equivalent sales (Mcf/day)	28,083	25,830	17,459
Average realized sales prices:			
Oil (\$/Bbl)	\$ 47.22	\$ 101.94	\$ 104.75
NGLs (\$/Bbl)	18.97	27.41	28.34
Natural gas (\$/Mcf)	2.60	4.07	3.63
Oil equivalent (\$/Boe)	16.40	25.53	23.96
Natural gas equivalent (\$/Mcf)	2.73	4.26	3.99
Average production costs: ⁽¹⁾			
Oil equivalent (\$/Boe)	\$ 8.96	\$ 10.73	\$ 12.46
Natural gas equivalent (\$/Mcf)	1.49	1.79	2.08

(1) Includes lease operating expenses and gathering and transportation costs.

Volume measurements:

Boe – barrel of oil equivalent

MBbls – thousand barrels for crude oil, condensate or NGLs

MBoe – thousand barrels of oil equivalent

Mcf – thousand cubic feet

MMcf – million cubic feet

MMcfe – million cubic feet of gas equivalent

The following is a description of the remainder of our top 10 properties, measured by proved reserves at December 31, 2015, three of which are located on the conventional shelf and five of which are located in the deepwater. We do not believe that individually any of these properties are of major significance (each has proved reserves which comprise less than 15% of our year-end total proved reserves, calculated on a natural gas equivalent basis).

Mississippi Canyon 243 Field (Matterhorn). Mississippi Canyon 243 field is located off the coast of Louisiana, approximately 100 miles southeast of New Orleans, in 2,552 feet of water. The field area covers Mississippi Canyon block 243, with a single floating, tension leg production platform. Société Nationale Elf Aquitaine discovered the field in 2002. We acquired a 100% working interest in the field from Total E&P USA Inc. (“Total E&P”) in 2010. Cumulative field production through 2015 is approximately 34.8 MMBoe gross (208.6 Bcfe gross). This field is a supra-salt (above the salt layer) development with 17 productive horizons at depths ranging to 9,850 feet. As of December 31, 2015, 30 wells have been drilled, 13 of which have been successful. During 2013, we drilled one well, which began production in 2013, and we drilled another well, that had reached target depth but had not yet been completed. During 2014, the well that had reached target depth in 2013 was completed. During December 2015, production from this field, net to our interest, averaged 1,831 barrels of crude oil per day, 299 barrels of NGLs per day and 4,710 Mcf of natural gas per day, for total production of 2,914 Boe per day (17,486 Mcfe per day).

Viosca Knoll 783 Field (Viosca Knoll 783 Lease (Tahoe) and Viosca Knoll 784 Lease (SE Tahoe)). The Viosca Knoll 783 field is located off the coast of Louisiana, approximately 140 miles southeast of New Orleans, in 1,500 to 1,700 feet of water. The field area covers Viosca Knoll blocks 783 and 784, with subsea tiebacks to two platforms in Main Pass 252. Shell discovered the Tahoe prospect in 1984 and the SE Tahoe prospect in 1996. We acquired a 70% working interest in the Tahoe lease and a 100% working interest in the SE Tahoe lease from Shell in 2010. We are the operator for these properties. Cumulative field production through 2015 is approximately 98.3 MMBoe gross (590.0 Bcfe gross). The Tahoe prospect is a supra-salt development with two productive horizons at depths ranging to 10,300 feet. The SE Tahoe prospect is also a supra-salt development with one productive horizon at a depth of 9,325 feet. As of December 31, 2015, 16 wells have been drilled at the Tahoe prospect, eight of which have been successful and one successful well has been drilled at the SE Tahoe prospect. During December 2015, production from this field, net to our interest, averaged 178 barrels of crude oil per day, 653 barrels of NGLs per day and 15,909 Mcf of natural gas per day, for total production of 3,483 Boe per day (20,896 Mcfe per day).

Mississippi Canyon 782 Field (Dantzer). Mississippi Canyon 782 field is located off the coast of Louisiana, approximately 160 miles southeast of New Orleans, in 6,600 feet of water. The field area covers Mississippi Canyon block 782 and 738. We have a 20% working interest, which is operated by Noble Energy. We, along with Noble Energy, discovered the field in 2013. This field is currently under development as a subsea tieback to the Thunderhawk Field approximately 12 miles to the northwest. The field is a three-way closure trapped against a salt wall. There are two pay horizons, the upper Miocene U5 and U6 sands. Cumulative field production through 2015 is approximately 65.5 MMBoe gross (392.8 Bcfe gross). As of December 31, 2015, two wells have been drilled, of which both have been successful, with one well beginning production in the fourth quarter of 2015 and the other well beginning production in the first quarter of 2016. During December 2015, production from this field, net to our interest, averaged 3,668 barrels of crude oil per day, 66 barrels of NGLs per day and 3,565 Mcf of natural gas per day, for total production of 4,328 Boe per day (25,969 Mcfe per day).

Main Pass 108 Field. Main Pass 108 field consists of Main Pass blocks 107, 108 and 109. This field is located off the coast of Louisiana approximately 50 miles east of Venice in 50 feet of water. We acquired our working interests in these blocks, which range from 33% to 100%, in a transaction with Kerr-McGee Oil and Gas Corporation (“Kerr-McGee”) and we are the operator for the majority of these properties. The field produces from a number of low relief, predominantly stratigraphically trapped sands. The productive interval ranges in age from Upper Miocene Big A through Middle Miocene Big Hum. As of December 31, 2015, 48 wells have been drilled in this field, 30 of which were successful. Cumulative field production through 2015 is approximately 54.5 MMBoe gross (326.7 Bcfe gross). One new well reached target depth in 2011 and began production in 2012. In addition, one workover was performed in 2012. In 2013, we drilled and completed one well, which began production during 2013. During December 2015, production from this field, net to our interest, averaged 281 barrels of crude oil per day, 295 barrels of NGLs per day and 15,279 Mcf of natural gas per day, for total production of 3,123 Boe per day (18,741 Mcfe per day).

Brazos A-133 Field. Brazos A-133 field is located 85 miles east of Corpus Christi, Texas in 200 feet of water. The field was discovered in 1978 by Cities Service Oil Company with production commencing in the same year. There are five active platforms, three of which are production platforms. Cumulative field production through 2015 is approximately 152.9 MMBoe gross (917.6 Bcfe gross) from the Middle Miocene Tex W and Big Hum sections. The bulk of the production is from the Big Hum CM-7 sand, which is a 4-way closure downthrown to the Corsair Fault and bisected by antithetic faults. The top of the CM-7 sand is at a subsea depth of 12,000 feet. Since its discovery, 22 wells have been drilled, of which 17 were successful. We own a 50% working interest, of which 25% was obtained through a transaction with Kerr-McGee in 2006 and an additional 25% was obtained through a transaction with Chevron U.S.A. Inc. in 2015. During December 2015, production from this field, net to our interest, averaged 44 barrels of crude oil per day and 18,017 Mcf of natural gas per day, for total production of 3,047 Boe per day (18,017 Mcfe per day).

Ewing Bank 910. Ewing Bank 910 is located approximately 68 miles off the Louisiana coast in 560 feet of water. The field area covers Ewing Bank blocks 910 and 954, and South Timbalier block 320. Kerr-McGee discovered the field in 1996. We own a 100% working interest in the main field pays, having acquired a 40% working interest from Kerr-McGee in 2006 and the remaining 60% from Petrobras America Inc. in 2014. Two recently successful deep wells are subject to a 50% working interest with Walter Oil and Gas. A single production platform is located on Block 910. Cumulative field production through 2015 is approximately 15.0 MMBoe gross (90.1 Bcfe gross). Production occurs from Pliocene and upper Miocene channel/levee sands. Hydrocarbons occur in combination stratigraphic and structural traps. A newly acquired wide angle azimuth seismic data set is expected to help confirm several recently identified drilling opportunities in the field area. Since its discovery, 10 wells have been drilled, of which eight were successful. During December 2015, production from this field, net to our interest, averaged 420 barrels of crude oil per day, 8 barrels of NGLs per day and 352 Mcf of natural gas per day, for total production of 487 Boe per day (2,920 Mcfe per day).

Mississippi Canyon 698 Field (Big Bend). Mississippi Canyon 698 is approximately 160 miles southeast of New Orleans in 7,221 feet of water. The field area covers portions of Mississippi Canyon blocks 697, 698, and 742. We have a 20% working interest, which is operated by Noble Energy. We, along with Noble Energy, discovered the field in 2012. This field is a subsea tieback to the Thunderhawk Field approximately 18 miles to the northwest. Cumulative field production through 2015 is approximately 46.1 MMBoe gross (276.9 Bcfe gross). The field is a supra-salt development with two productive horizons at depths ranging from 14,660' to 15,533' total vertical depth. As of December 31, 2015, one well has been drilled and successful, with the well beginning production in the fourth quarter of 2015. During December 2015, production from this field, net to our interest, averaged 3,159 barrels of crude oil per day, 23 barrels of NGLs per day and 1,386 Mcf of natural gas per day, for total production of 3,413 Boe per day (20,478 Mcfe per day).

Mississippi Canyon 582 Field (Medusa). Mississippi Canyon 582 field is located off the coast of Louisiana approximately 110 miles south-southeast of New Orleans in 2,200 feet of water. The field area covers Mississippi Canyon blocks 538, 582 and 583. Murphy Exploration and Production Company discovered the field in 1999 and is the operator. First production commenced in 2003. We acquired a 15% working interest in the field from Callon in 2013. The Medusa Spar facility is located on Block 582. Production occurs from late Miocene to early Pliocene deep water, channel/levee sand reservoirs. Hydrocarbon traps are a combination of both structural and stratigraphic traps. Since its discovery, 14 wells have been drilled, of which nine wells are currently producing. Additional drilling opportunities have been identified and are currently being evaluated. Cumulative field production through 2015 is approximately 74.6 MMBoe gross (447.8 Bcfe gross). During December 2015, production from this field, net to our interest, averaged 1,478 barrels of crude oil per day, 87 barrels of NGLs per day and 1,215 Mcf of natural gas per day, for total production of 1,767 Boe per day (10,602 Mcfe per day).

Proved Reserves

Our proved reserves were estimated by NSAI, our independent petroleum consultant, and amounts provided in this Form 10-K are consistent with filings we make with other federal agencies. Our proved reserves as of December 31, 2015 are summarized below and the mix by product was 46% oil, 9% NGLs and 45% natural gas determined using the energy-equivalent ratio noted below.

Classification of Proved Reserves (1)	Total Energy-Equivalent Reserves (2)						
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)	Natural Gas Equivalent (Bcfe)	% of Total Proved	PV-10 (3) (In millions)
Proved developed producing	23.8	5.7	168.1	57.6	345.5	75 %	\$ 775
Proved developed non-producing	5.6	0.7	30.4	11.4	68.0	15 %	128
Total proved developed	29.4	6.4	198.5	69.0	413.5	90 %	903
Proved undeveloped	6.1	0.2	6.9	7.4	44.6	10 %	63
Total proved	35.5	6.6	205.4	76.4	458.1	100 %	\$ 966

Volume measurements:

MMBbls – million barrels for crude oil, condensate or NGLs

MMBoe – million barrels of oil equivalent

Bcf – billion cubic feet

Bcfe – billion cubic feet of gas equivalent

- (1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2015 were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the year end December 31, 2015. Prices were adjusted by field for quality, transportation, fees, energy content and regional price differentials. For crude oil, the West Texas Intermediate posted price was used in the calculation and, after adjustments, a price of \$46.94 per barrel was used in computing the amounts above. For NGLs, a ratio was computed for each field of the NGLs realized price compared to the crude oil realized price. Then, this ratio was applied to the crude oil price using SEC guidance. The NGLs price of \$17.60 per barrel was used in computing the amounts above. For natural gas, the average Henry Hub spot price was used in the calculation and the adjusted price of \$2.50 per Mcf was used in computing the amounts above. Such prices were held constant throughout the estimated lives of the reserves. Future production and development costs are based on year-end costs with no escalations.
- (2) Energy equivalents are determined using the energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs (totals may not compute due to rounding). The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent price for oil and NGLs may differ significantly.
- (3) We refer to PV-10 as the present value of estimated future net revenues of estimated proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs and excludes ARO. We have also included PV-10 after ARO below. PV-10 after ARO includes the present value of ARO related to proved reserves using a 10% discount rate and no inflation of current costs. Neither PV-10 nor PV-10 after ARO are financial measures defined under GAAP; therefore, the following table reconciles these amounts to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that the non-GAAP financial measures of PV-10 and PV-10 after ARO are relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. PV-10 and PV-10 after ARO are used internally when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. We believe the use of pre-tax measures is valuable because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid. Management believes that the presentation of PV-10 and PV-10 after ARO provide useful information to investors because they are widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. PV-10 and PV-10 after ARO are not measures of financial or operating performance under GAAP, nor are they intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 and PV-10 after ARO should not be considered in isolation or as substitutes for the standardized measure of discounted future net cash flows as defined under GAAP.

The reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves is as follows (in millions):

	December 31, 2015
Present value of estimated future net revenues (PV-10)	\$ 966
Present value of estimated ARO, discounted at 10%	(352)
PV-10 after ARO	614
Future income taxes, discounted at 10%(1)	—
Standardized measure of discounted future net cash flows	\$ 614

- (1) No future income taxes were estimated to be paid as our present tax position has sufficient tax basis and net operating loss carrying forwards to offset any future taxes. State income taxes were disregarded due to immateriality.

Changes in Proved Reserves

Our total proved reserves at December 31, 2015 were 76.4 MMBoe compared to 120.0 MMBoe at December 31, 2014, a decrease of 43.6 MMBoe. Total proved reserves at December 31, 2014, excluding the reserves attributable to the Yellow Rose field were 82.7 MMBoe. The primary causes were reductions due to the sale of the Spraberry field (Yellow Rose), reductions from lower commodity prices and reductions from production. Partially offsetting were increases from revisions, extensions and discoveries. Reductions related to the Yellow Rose field were comprised of 17.4 MMBoe reserve reductions prior to the sale (primarily related to lower commodity prices) and 19.0 MMBoe reserve reductions from the sale in October 2015. The reduction due to lower commodity prices on reserve balances at December 31, 2015 was estimated at 10.7 MMBoe and production reduced reserve balances by 17.0 MMBoe, of which 0.8 MMBoe was related to the Yellow Rose field. Net increases were from revisions of 15.4 MMBoe, extensions and discoveries of 4.1 MMBoe, and purchases of 1.0 MMBoe.

See *Development of Proved Undeveloped Reserves* below for a table reconciling the change in proved undeveloped reserves during 2015. See *Financial Statements and Supplementary Data— Note 21 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K for additional information.

Our estimates of proved reserves, PV-10 and standardized measure as of December 31, 2015 are calculated based upon SEC mandated 2015 unweighted average first-day-of-the-month crude oil and natural gas benchmark prices, which may or may not represent current prices. Using the SEC methodology and prior to certain adjustments for quality, transportation, fees, energy content and regional price differentials, the price of crude oil declined to \$46.79 per barrel for 2015 year-end compared to \$91.48 per barrel for 2014 year-end. For natural gas, the price declined to \$2.59 per MMBtu for 2015 year-end 2015 compared to \$4.35 for 2014 year-end. Sustained current prices will result in the prices used in our estimates through year-end 2016 to be substantially lower, which, absent significant proved reserve additions, will reduce future estimated proved reserve volumes due to lower economic limits and economic return thresholds for undeveloped reserves, as well as impact our results of operations, cash flows, quarterly full cost impairment ceiling tests and volume-dependent depletion cost calculations. See *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 in this Form 10-K for additional information.

Qualifications of Technical Persons and Internal Controls over Reserves Estimation Process

Our estimated proved reserve information as of December 31, 2015 included in this Form 10-K was prepared by our independent petroleum consultants, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The scope and results of their procedures are summarized in a letter included as an exhibit to this Form 10-K. The primary technical person at NSAI responsible for overseeing the preparation of the reserves estimates presented herein has B.S. and M.S. degrees in Civil Engineering and has been a Registered Professional Engineer in the State of Texas for 27 years and a member of the Society of Petroleum Engineers for over 30 years. He has over 38 years total experience in the oil and gas industry, with over 24 years of reservoir engineering experience. His areas of experience are the continental shelf and deepwater Gulf of Mexico, San Juan Basin, onshore and offshore Mexico, offshore Africa, and unconventional gas sources worldwide. NSAI has informed us that he meets or exceeds the education, training, and experience requirements set forth in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

We maintain an internal staff of reservoir engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates. Additionally, our senior management reviews any significant changes to our proved reserves on a quarterly basis. Our Reservoir Engineering Director has served in that capacity since 2013, as Reservoir Engineering Manager since 2006, and as Staff Reservoir Engineer upon joining the Company in 2004. Prior to joining the Company, he served as a Reservoir Engineer at Shell, then VP of Reservoir Engineering at Freeport-McMoRan Oil & Gas and later as Manager Acquisitions Engineering at Matrix Oil & Gas. He received a Bachelor of Science degree in Engineering Science from Iowa State University in 1972.

Reserve Technologies

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our independent petroleum consultant employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, severance taxes, development costs and workovers, all of which may vary considerably from actual results;
- the accuracy of various mandated economic assumptions such as the future prices of crude oil, NGLs and natural gas; and
- the judgment of the persons preparing the estimates.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered.

Reporting of Natural Gas and Natural Gas Liquids

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. We report all natural gas production information net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs. We convert barrels to Mcfe using an energy-equivalent ratio of six Mcf to one barrel of oil, condensate or NGLs. This energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for crude oil, NGLs and natural gas may differ substantially.

Development of Proved Undeveloped Reserves

Our proved undeveloped reserves (“PUDs”) were estimated by NSAI, our independent petroleum consultant. Future development costs associated with our PUDs at December 31, 2015 were estimated at \$124.1 million.

The following table presents our PUDs by field (in million barrels of oil equivalent):

	December 31,		
	2015	2014	2013
Ship Shoal 349 (Mahogany)	4.0	2.1	1.3
Mississippi Canyon 243 (Matterhorn)	2.0	1.4	1.3
Viosca Knoll 823 (Virgo)	—	2.0	1.4
Spraberry (Yellow Rose)	—	24.9	25.7
Mississippi Canyon 698 (Big Bend)	0.9	1.9	1.9
Mississippi Canyon 538/582 (Medusa)	—	0.3	—
Mississippi Canyon 782 (Dantzler)	—	4.1	—
Ewing Bank 910	0.5	—	—
Total	7.4	36.7	31.6

The following table presents a reconciliation of our PUDs (in million barrels of oil equivalent):

	Year Ended December 31,		
	2015	2014	2013
Proved undeveloped reserves, beginning of year	36.7	31.6	30.6
Reductions:			
Ship Shoal 349 (Mahogany)	—	—	(4.8)
Mississippi Canyon 243 (Matterhorn)	—	—	(0.7)
Spraberry (Yellow Rose) divestiture	(24.9)	—	—
Spraberry (Yellow Rose) drilling, completions and technical	—	(2.3)	(4.6)
Spraberry (Yellow Rose) well performance and viability	—	(2.4)	(1.5)
Mississippi Canyon 698 (Big Bend)	(1.0)	—	—
Viosca Knoll 823 (Virgo)	(2.0)	—	—
Mississippi Canyon 538/582 (Medusa)	(0.3)	—	—
Mississippi Canyon 782 (Dantzler)	(4.1)	—	—
High Island 21/22	—	—	(2.7)
Subtotal - reductions	(32.3)	(4.7)	(14.3)
Balance after reductions	4.4	26.9	16.3
Additions:			
Ship Shoal 349 (Mahogany)	1.9	0.8	1.3
Viosca Knoll 823 (Virgo)	—	0.6	—
Spraberry (Yellow Rose) well additions and other	—	3.9	7.9
Spraberry (Yellow Rose) 40 acre down-spacing in 2013	—	—	4.2
Mississippi Canyon 698 (Big Bend)	—	—	1.9
Mississippi Canyon 782 (Dantzler)	—	4.1	—
Mississippi Canyon 243 (Matterhorn)	0.6	—	—
Ewing Bank 910	0.5	—	—
Other changes	—	0.4	—
Subtotal - additions	3.0	9.8	15.3
Proved undeveloped reserves, end of year	7.4	36.7	31.6

Activity related to PUDs in 2015:

- During 2015, we completed five offshore wells which affected the conversion of PUDs to proved developed producing reserves (“PDPs”) and affected additional PUDs to be recognized. Three of the five wells were drilled prior to 2015. Approximately \$141.0 million of capital expenditures was incurred related to these five wells during 2015. Activity, divestitures and development assessments in 2015 resulted in reclassification of approximately 88% of the PUDs existing at December 31, 2014.
- At our Spraberry field (Yellow Rose), our interests were divested and we were assigned an ORRI.
- At our Mississippi Canyon 698 field (Big Bend), we completed one well which moved PUDs to PDPs.
- At our Viosca Knoll 823 field (Virgo), one well was removed from PUDs as the development timing was beyond the five year limitation and another well was removed from PUDs as it was determined to be uneconomic.
- At our Mississippi Canyon 782 field (Dantzler), we completed two wells which moved PUDs into PDPs.
- At our Ship Shoal 349 field (Mahogany), PUD reserves were added based on performance, remapping and technical changes.
- At our Mississippi Canyon 243 field (Matterhorn), PUD reserves were added due to the assessment related to two wells.

Activity related to PUDs in 2014:

- During 2014, we drilled 20 development wells that converted PUDs to PDPs and spent \$149.5 million on development of PUDs. Activity in 2014 allowed reclassification of approximately 15% of the PUDs existing at December 31, 2013.
- At our Spraberry field (Yellow Rose), we drilled and completed 20 development wells, which moved PUDs to PDPs. In addition, PUDs were decreased due to certain wells being evaluated as uneconomic due to performance and for technical reasons. PUDs were increased due to exploration drilling activity, both by us and offset operators. Our drilling activity for 2015 is expected to be lower compared to 2014, then increasing in 2016 and beyond as prices recover.
- At our Ship Shoal 349 field (Mahogany), we experienced technical difficulties from a cracked casing, which led us to abandon the well. As of December 31, 2014, we were in the process of drilling a new well (the A-18 well) which was expected to convert the undeveloped reserves to PDP’s, but have stacked the rig in the first quarter of 2015 due to substantially reduced crude oil prices. We plan to commence drilling this well once crude oil prices recover.
- The PUDs at our Mississippi Canyon 782 field (Dantzler) were added as a result of drilling activity in 2013 and completion operations in 2014 to classify reserves as proved undeveloped. This field is not operated by us so we are subject to the decisions of the operator. Current plans are to complete the two wells in this field in 2015 that have been drilled to target depth and to begin production in the first quarter of 2016.
- At our Viosca Knoll 823 field (Virgo), we have elected to add a PUD to replace declining reserves in the field. This decision was made due to the magnitude of the reserve potential. We perceived less risk in a sidetrack of an existing well compared to a major workover to produce these reserves.

Activity related to PUDs in 2013:

- During 2013, we drilled numerous development wells that converted PUDs to PDPs and spent \$270.4 million on development of PUDs. Activity in 2013 allowed reclassification of approximately 47% of the PUDs existing at December 31, 2012.
- At our Ship Shoal 349 field (Mahogany), we drilled and completed the SS 359 A14 BP2 well, which resulted in the conversion of all of the PUDs existing at 2012 to PDPs in 2013. The SS 359 A14 BP2 well was the fifth well drilled under our 2010 Development Plan. As of December 31, 2013, we were in the process of drilling our sixth well (SS 359 A015) under this multi-well program. This multi-well program is expected to continue into 2014 and beyond. Also, as a result of our successful drilling program, one new PUD location was added during 2013.

- The PUDs at our Mississippi Canyon 243 field (Matterhorn) and our Viosca Knoll 823 field (Virgo) were obtained through acquisitions in 2010. We drilled and completed one development well (MC 243 A2 ST2 BP2) at the Mississippi Canyon 243 field (Matterhorn), which moved PUDs to PDPs. Also, one new PUD location was added during 2013. Development of these two fields is expected to continue into future years.
- PUDs at our Spraberry field (Yellow Rose) were obtained primarily through an acquisition in 2011. We drilled and completed 33 development wells, which moved PUDs to PDPs. In addition, PUDs were decreased due to certain wells being evaluated as uneconomical due to performance and for technical reasons. PUDs were increased due to exploration drilling activity, both by us and other companies, and also from additions related to 40 acre down-spacing. Our drilling plans for 2014 include an active drilling program in the Spraberry field (Yellow Rose) and we expect to continue our drilling activity beyond 2014.
- In the High Island 21/22 field, we drilled and completed the HI 0021 A1 BP1 well, which initially resulted in the conversion of all the PUDs to PDPs. Subsequently, these PDPs were removed from proved reserves due to well performance.
- The additional PUDs at the Mississippi Canyon 698 field (Big Bend) were from our joint interest ownership in the non-operated field and are related to the MC 698 #1 well, which was drilled in 2012.

See *Business* under Part I, Item 1, *Our Fields* in Item 2 above and *Financial Statements and Supplementary Data – Note 2 – Acquisitions and Divestitures* under Part II, Item 8 in this Form 10-K for additional information.

We believe that we will be able to develop all but 1.2 MMBoe of the reserves classified as PUDs, or approximately 16%, out of the total of 7.4 MMBoe classified as PUDs at December 31, 2015, within five years from the date such reserves were initially recorded. The exception is at the Mississippi Canyon 243 field (Matterhorn) where the field is being developed using a single floating tension leg platform requiring an extended sequential development plan. The platform cannot support a rig that would allow additional wells to be drilled, but can support a rig to allow sidetracking of wells. A portion of the PUDs in this field were originally recorded in our reserves as of December 31, 2010. The development of these PUDs will be delayed until an existing well is depleted and available to sidetrack. Based on the latest reserve report, a well is expected to be drilled to develop the Mississippi Canyon 243 field (Matterhorn) PUDs in 2020.

Our capital budget for 2016 of \$15 million allocates minimal amounts for development to occur in 2016. While our long-term plans include development of our PUDs, with the exception noted above, continued low levels of investments in development in years beyond 2016 may lead to derecognizing PUDs or postponing their development due to change of circumstances. A recovery in crude oil prices could lead to an increase in development expenditures and much faster conversion of PUDs to PDPs.

Acreage

The following summarizes our leasehold at December 31, 2015. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	468,692	312,014	76,642	76,642	545,334	388,656
Deepwater	179,331	76,433	169,667	77,607	348,998	154,040
Total	648,023	388,447	246,309	154,249	894,332	542,696

Approximately 72% of our total net offshore acreage is developed. We have the right to propose future exploration and development projects on the majority of our acreage.

For the offshore undeveloped leasehold, 16,140 net acres (10%) of the total 154,249 net undeveloped offshore acres could expire in 2016, 50,380 net acres (33%) could expire in 2017, 36,377 net acres (24%) could expire in 2018, 38,480 net acres (25%) could expire in 2019, and 12,872 net acres (8%) could expire in 2020 and beyond. In making decisions regarding drilling and operations activity for 2016 and beyond, we give consideration to undeveloped leasehold that may expire in the near term in order that we might retain the opportunity to extend such acreage.

Our net offshore acreage decreased 155,776 net acres (22%) from December 31, 2014 primarily due to expired undeveloped leases and undeveloped leases which were relinquished to reduce lease rental payments. Substantially all of our onshore acreage was sold during 2015 primarily with the sale of the Yellow Rose field. The remaining immaterial onshore acreage as of December 31, 2015 will have expired, will be sold, or relinquished during the first half of 2016.

Production

For the years 2015, 2014 and 2013, our net daily production averaged 46,709 Boe, 48,317 Boe and 49,276 Boe, respectively. Production decreased in 2015 from 2014 primarily due to natural production declines, the sale of the Yellow Rose field and partially offset by acquisitions, discoveries and recompletions. Production decreased in 2014 from 2013 primarily due to an out of period adjustment of 0.9 MBoe/day recorded in 2013, natural production declines, production deferrals and divestitures, partially offset by acquisitions and new production. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations* under Part II, Item 7 in this Form 10-K for additional information.

Production History

The following presents historical information about our produced oil, NGLs and natural gas volumes from all of our producing fields over the past three years.

	Year Ended December 31,		
	2015	2014	2013
Net Sales:			
Oil (MBbls)	7,751	7,176	7,018
NGLs (MBbls)	1,604	2,112	2,091
Oil and NGLs (MBbls)	9,355	9,288	9,110
Natural gas (MMcf)	46,163	50,088	53,257
Total oil equivalent (MBoe)	17,049	17,636	17,986
Total natural gas equivalents (MMcfe)	102,294	105,815	107,915

Volume measurements:

MBbls – thousand barrels for crude oil, condensate or NGLs

MBoe – thousand barrels of oil equivalent

MMcf – million cubic feet

MMcfe – million cubic feet equivalent

Refer to the descriptions of our 10 largest fields reported earlier in this Item 2, *Properties*, for historical information about our produced volumes from our Ship Shoal 349/359 field (Mahogany) and the Fairway Field over the past three fiscal years, which have proved reserves exceeding 15% of our total proved reserves. Also refer to *Selected Financial Data – Historical Reserve and Operating Information* under Part II, Item 6 in this Form 10-K for additional historical operating data, including average realized sale prices and production costs.

Productive Wells

The following presents our ownership interest at December 31, 2015 in our productive oil and natural gas wells. A net well represents our fractional working interest of a gross well in which we own less than all of the working interest.

Offshore Wells	Oil Wells (1)		Gas Wells (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	80	59	54	37	134	96
Non-operated	33	8	20	8	53	16
Total offshore wells	113	67	74	45	187	112

(1) Includes six gross (3.6 net) oil wells and four gross (2.5 net) gas wells with multiple completions.

Drilling Activity

As presented in the tables below, our drilling activity decreased in 2015 compared to 2014 and 2013 in our onshore operations. In 2014, we increased the onshore horizontal drilling activity compared to 2013, which take longer to drill and are more expensive on a per well basis compared to vertical wells. Our onshore drilling activity was primarily in the Yellow Rose field, which was acquired by acquisition in May 2011 and was sold in October 2015.

The tables below are based on the SEC's criteria of completion or abandonment to determine productive wells drilled.

Development Drilling

The following table summarizes our development wells drilled over the past three years.

	Year Ended December 31,		
	2015	2014	2013
Gross Wells:			
Productive:			
Offshore	—	1	4
Onshore	3	20	33
Total development wells - gross	3	21	37
Net Wells:			
Productive:			
Offshore	—	1.0	4.0
Onshore	2.3	19.3	32.9
Total development wells - net	2.3	20.3	36.9

Our success rates related to our development wells drilled was 100% in each of the last three years.

Exploration Drilling

The following table summarizes our exploration wells drilled over the past three years.

	Year Ended December 31,		
	2015	2014	2013
Gross Wells:			
Productive:			
Offshore	5	5	1
Onshore	2	13	7
Non-productive:			
Offshore	—	—	1
Total exploration wells - gross	<u>7</u>	<u>18</u>	<u>9</u>
Net Wells:			
Productive:			
Offshore	1.2	3.4	1.0
Onshore	1.9	13.0	6.9
Non-productive:			
Offshore	—	—	1.0
Total exploration wells - net	<u>3.1</u>	<u>16.4</u>	<u>8.9</u>

Our success rates related to our exploration wells drilled during 2015, 2014 and 2013 were 100%, 100% and 89%, respectively. We had only one non-successful well in the last three years, which occurred in 2013.

Recent Drilling Activity

As of February 15, 2016, we were in the process of completing one offshore exploration well at the Ewing Bank 910 field (the EW 0954 A-8 well). At the Ship Shoal 349 field (Mahogany), a well was spud in 2014, but drilling was suspending during 2015 with the rig stacked at the platform.

Capital Expenditures

The level of our investment in oil and gas properties changes from time to time depending on numerous factors, including the prices of crude oil, NGLs and natural gas, acquisition opportunities and the results of our exploration and development activities. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Expenditures* under Part II, Item 7 in this Form 10-K for capital expenditures information.

Item 3. Legal Proceedings

Apache Lawsuit. In December 2014, Apache Corporation (“Apache”) filed a lawsuit against W&T Offshore, Inc., alleging that W&T breached the joint operating agreement related to plugging and abandonment costs for three deepwater wells in the Mississippi Canyon area of the Gulf of Mexico. We contend that the costs incurred by Apache are excessive and unreasonable. Apache seeks unspecified actual damages, interest, court costs and attorneys’ fees. See *Financial Statements and Supplementary Data - Note 18 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information on this matter.

Claims against Certain Insurance Underwriters. In June 2014, the United States Fifth Circuit reversed a lower court's ruling in holding that our excess liability policies ("Excess Policies") cover removal-of-wreck and debris claims arising from Hurricane Ike, even though we exhausted the limits of our Energy Package (defined as certain insurance policies relating to our oil and gas properties which includes named windstorm coverage) with non-removal-of-wreck and debris claims. Several of the underwriters have not paid us amounts we claim are due under such Excess Policies in accordance with the Fifth Circuit ruling. We filed a lawsuit in September 2014 against certain underwriters for amounts owed, interest, attorney fees and damages. After receiving reimbursements applied against our remaining Energy Package limits, reimbursement from certain underwriters of the Excess Policies of approximately \$10 million and adjustments to claims, the estimated potential reimbursement of removal-of-wreck costs is approximately \$31 million, plus interest, attorney fees and damages, if any. See *Financial Statements and Supplementary Data - Note 18 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information.

Monetary Sanctions by Government Authorities. During 2015, the Company received four final notices from the BSEE of civil penalties related to Incidents of Noncompliance ("INCs") at various offshore locations. An aggregate \$0.2 million has been paid in respect of three of the four final notices. The Company also received three proposed notices from BSEE related to INCs at various offshore locations. The occurrence dates range from July 2012 to June 2014. For the unpaid proposed penalties, the Company has accrued \$1.0 million, which is the Company's best estimate of the final settlement once all appeals have been exhausted. The proposed amounts by the BSEE for the unpaid proposed penalties total \$8.1 million. The Company's position is that the proposed civil penalties are excessive given the specific facts and circumstances related to each of the INCs.

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

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

Other Litigation. 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 consolidated financial condition, cash flow or results of operations.

Executive Officers of the Registrant

The following lists our executive officers:

Name	Age (1)	Position
Tracy W. Krohn	61	Founder, Chairman, Director and Chief Executive Officer
Jamie L. Vazquez	55	President
John D. Gibbons	62	Senior Vice President and Chief Financial Officer
Thomas P. Murphy	53	Senior Vice President and Chief Operations Officer
Stephen L. Schroeder	53	Senior Vice President and Chief Technical Officer
Thomas F. Getten	68	Vice President, General Counsel and Secretary

(1) Ages as of February 23, 2016.

Tracy W. Krohn has served as Chief Executive Officer since he founded the Company in 1983 and as Chairman since 2004. He also served as President of the Company until September 2008. During 1996 to 1997, Mr. Krohn was Chairman and Chief Executive Officer of Avira Energy Corporation. Prior to founding the Company, from 1982 to 1983, Mr. Krohn was a senior engineer with Taylor Energy, and he began his career as a petroleum engineer and offshore drilling supervisor with Mobil Oil Corporation.

Jamie L. Vazquez joined the Company in 1998 as Manager of Land and in 2003 she was named Vice President of Land. In September 2008, Ms. Vazquez was appointed President of the Company. Prior to joining the Company, Ms. Vazquez was with CNG Producing Company for 17 years, holding positions of increasing responsibility ending as Manager, Land/Business Development Gulf of Mexico.

John D. Gibbons joined the Company in February 2007 as Senior Vice President and Chief Financial Officer. Prior to joining the Company, Mr. Gibbons was Senior Vice President and Chief Financial Officer of Westlake Chemical Corporation from March 2006 to February 2007. Prior to joining Westlake, Mr. Gibbons was with Valero Energy Corporation for 23 years, holding positions of increasing responsibility ending as Executive Vice President and Chief Financial Officer.

Thomas P. Murphy joined the Company in June 2012 as Senior Vice President and Chief Operations Officer. From 2009 to 2012, Mr. Murphy worked at Woodside Energy USA Inc. as Vice President Engineering and Operations. From 2008 to 2009 he worked for PetroQuest Energy, Inc. as Vice President Engineering. From 2000 to 2008, Mr. Murphy worked for Devon Energy Corporation in a variety of positions, including Gulf of Mexico Deep-Water Development Supervisor, New Business Development Supervisor and culminating in his position as Sr. Exploration Advisor.

Stephen L. Schroeder joined the Company in 1998 and served as Production Manager from 1999 until 2005. In 2005, Mr. Schroeder was named Vice President of Production and in July 2006 he was named Senior Vice President and Chief Operating Officer. In June 2012, Mr. Schroeder was named Senior Vice President and Chief Technical Officer. Prior to joining the Company, Mr. Schroeder was with Exxon USA for 12 years holding positions of increasing responsibility, ending with Offshore Division Reservoir Engineer.

Thomas F. Getten joined the Company in July 2006 as Vice President, General Counsel and Assistant Secretary. In December 2011, Mr. Getten was appointed to the position of Corporate Secretary. Prior to joining the Company, Mr. Getten served as a partner with King, LeBlanc & Bland, P.L.L.C., a New Orleans law firm, since February 2001. From 1996 to December 2000, Mr. Getten served as Vice President, Secretary and General Counsel of Forcenergy Inc until its merger into Forest Oil Corporation.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed and principally traded on the NYSE under the symbol "WTT". The following table sets forth the high and low sales price of our common stock as reported on the NYSE.

	High	Low
2015:		
First Quarter	\$ 7.28	\$ 5.08
Second Quarter	6.80	5.24
Third Quarter	5.42	2.86
Fourth Quarter	4.00	2.05
2014:		
First Quarter	17.33	13.52
Second Quarter	19.78	14.00
Third Quarter	16.75	10.87
Fourth Quarter	11.32	5.34

As of March 3, 2016, there were 195 registered holders of our common stock.

Dividends

During 2015, no dividends were paid as dividend payments have been suspended. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* under Part II, Item 7 and *Financial Statements and Supplementary Data – Note 7 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for more information regarding covenants related to dividends in our debt agreements.

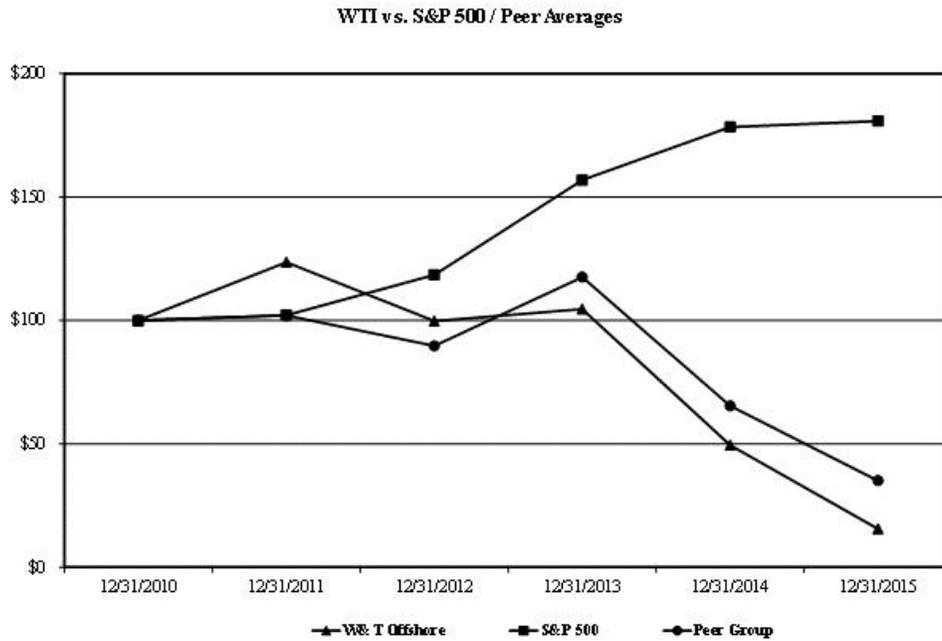
The following reflects the frequency and amounts of all cash dividends declared during 2014 (in thousands, except per share data):

	Aggregate Dividends on Common Stock	Dividends per Share of Common Stock
2014:		
First Quarter	\$ 7,562	\$ 0.10
Second Quarter	7,566	0.10
Third Quarter	7,566	0.10
Fourth Quarter	7,566	0.10

Dividends are subject to certain statutory requirements which include positive net equity. Our Board of Directors decides the timing and amounts of any dividends for the Company. Dividends are subject to periodic review of the Company's performance, which includes the current economic environment and applicable debt agreement restrictions. Our Board of Directors has suspended the regular quarterly dividend.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of \$100 in our common stock and the reinvestment of all dividends thereafter. The information contained in the graph below is furnished and not filed, and is not incorporated by reference into any document that incorporates this Annual Report on Form 10-K by reference.



Our peer group is comprised of Apache Corporation, Bill Barrett Corp., Cabot Oil & Gas Corp., Comstock Resources, Inc., Energy XXI (Bermuda) Limited, Forest Oil Corp., Newfield Exploration Co., SM Energy Co., SandRidge Energy, Inc., Stone Energy Corp., and Swift Energy Company.

Forest Oil Corp. merged with another company during December 2014 and its shares were excluded from the peer group.

Securities Authorized for Issuance Under Equity Compensation Plans

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K. For descriptions of the plans and additional information, see *Financial Statements and Supplementary Data – Note 10 – Incentive Compensation Plan and Note 11 – Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 in this Form 10-K.

Issuer Purchases of Equity Securities

For the year 2015, we did not purchase any of our equity securities.

The following table sets forth information about restricted stock units delivered by employees during the quarter ended December 31, 2015 to satisfy tax withholding obligations on the vesting of restricted stock units.

<u>Period</u>	<u>Total Number of Restricted Stock Units Delivered</u>	<u>Average Price per Restricted Stock Unit</u>	<u>Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs</u>	<u>Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs</u>
October 1, 2015 - October 31, 2015	N/A	N/A	N/A	N/A
November 1, 2015 - November 30, 2015	N/A	N/A	N/A	N/A
December 1, 2015 - December 31, 2015	495,935	\$ 2.82	N/A	N/A

Item 6. Selected Financial Data
SELECTED HISTORICAL FINANCIAL INFORMATION

The selected historical financial information set forth below should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 and with *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K.

	Year Ended December 31,				
	2015 ⁽¹⁾	2014 ⁽²⁾	2013 ⁽³⁾	2012 ⁽⁴⁾	2011 ⁽⁵⁾
(In thousands, except per share data)					
Consolidated Statement of Operations Information:					
Revenues:					
Oil	\$ 349,191	\$ 652,776	\$ 718,944	\$ 629,548	\$ 643,222
NGLs	27,665	72,837	73,345	84,637	105,559
Natural gas	123,435	217,816	189,290	158,390	221,194
Other	6,974	5,279	2,509	1,916	1,072
Total revenues	<u>507,265</u>	<u>948,708</u>	<u>984,088</u>	<u>874,491</u>	<u>971,047</u>
Operating costs and expenses:					
Lease operating expenses	192,765	264,751	270,839	232,260	219,206
Production taxes	3,002	7,932	7,135	5,840	4,275
Gathering and transportation	17,157	19,821	17,510	14,878	16,920
Depreciation, depletion and amortization	373,368	490,469	430,611	336,177	299,015
Asset retirement obligations accretion	20,703	20,633	20,918	20,055	29,771
Ceiling test write-down of oil and natural gas ⁽⁶⁾ properties	987,238	—	—	—	—
General and administrative expenses	73,110	86,999	81,874	82,017	74,296
Derivative (gain) loss	(14,375)	(3,965)	8,470	13,954	(1,896)
Total costs and expenses	<u>1,652,968</u>	<u>886,640</u>	<u>837,357</u>	<u>705,181</u>	<u>641,587</u>
Operating income (loss)	(1,145,703)	62,068	146,731	169,310	329,460
Interest expense, net of amounts capitalized	97,336	78,396	75,581	49,994	42,516
Loss on extinguishment of debt ⁽⁷⁾	—	—	—	—	22,694
Other (income) expense, net ⁽⁸⁾	4,663	(208)	(8,946)	(215)	(84)
Income (loss) before income tax expense (benefit)	(1,247,702)	(16,120)	80,096	119,531	264,334
Income tax expense (benefit)	(202,984)	(4,459)	28,774	47,547	91,517
Net income (loss)	<u>\$ (1,044,718)</u>	<u>\$ (11,661)</u>	<u>\$ 51,322</u>	<u>\$ 71,984</u>	<u>\$ 172,817</u>
Basic and diluted earnings (loss) per common share	\$ (13.76)	\$ (0.16)	\$ 0.68	\$ 0.95	\$ 2.29
Dividends on common stock ⁽⁹⁾	—	30,260	58,846	82,832	58,756
Cash dividends per common share	—	0.40	0.78	1.11	0.79
Consolidated Cash Flow Information:					
Net cash providing by operating activities ⁽¹⁰⁾	\$ 132,554	\$ 473,973	\$ 562,708	\$ 358,353	\$ 493,122
Capital expenditures - oil and natural gas properties ⁽¹¹⁾	230,161	626,612	634,378	684,863	719,026

	December 31,				
	2015	2014	2013	2012	2011
(In thousands)					
Consolidated Balance Sheet Information:					
Cash and cash equivalents	\$ 85,414	\$ 23,666	\$ 15,800	\$ 12,245	\$ 4,512
Total assets ⁽¹⁰⁾	1,208,022	2,689,508	2,497,180	2,337,615	1,860,868
Long-term debt ⁽¹⁰⁾	1,196,855	1,352,120	1,195,883	1,076,506	710,950
Shareholders' equity (deficit)	(526,491)	509,308	540,610	541,187	544,574

- (1) In the fourth quarter of 2015, we sold our interest in the Yellow Rose field.
- (2) In the second quarter of 2014, we acquired the Woodside Properties from Woodside and, in the third quarter of 2014, we acquired the remaining working interest in the Fairway Field and the associated Yellowhammer gas processing plant that we did not already own.
- (3) In the fourth quarter of 2013, we acquired the Callon Properties from Callon.
- (4) In the fourth quarter of 2012, we acquired the properties from Newfield Exploration Company and its subsidiary Newfield Exploration Gulf Coast LLC.
- (5) In the second quarter of 2011, we acquired certain oil and gas leasehold interests from Opal Resources LLC and Opal Resources Operating Company LLC and, in the third quarter of 2011, we acquired 64.3% working interest in the Fairway Field and the associated Yellowhammer gas processing plant from Shell.
- (6) In 2015, we incurred impairment charges for ceiling test write-downs of our oil and gas properties due to substantial reductions in commodity prices.
- (7) In 2011, we expensed repurchase premiums, deferred financing costs and other costs totaling \$22.0 million related to the repurchase of \$450.0 million in aggregate principal amount of our 8.25% Senior Notes due 2014.
- (8) In 2015, other (income)/expense, net include \$3.2 million for write-downs of debt issuance costs related to reductions of the borrowing base of the revolving bank credit facility. In 2013, other (income)/expense, net consisted primarily of payments received in conjunction with an option exercised by a counterparty.
- (9) The years 2013, 2012 and 2011 included special dividends of \$31.8 million (\$0.42 per share), \$59.0 million (\$0.79 per share) and \$46.9 million (\$0.63 per share), respectively. No special dividends were paid in 2014.
- (10) Prior periods were retrospectively adjusted to conform to the current year presentation related to the early adoption of certain accounting standards and for other conforming adjustments.
- (11) Reported on an accrual basis.

HISTORICAL RESERVE AND OPERATING INFORMATION

The following tables present summary information regarding our estimated net proved oil, NGLs and natural gas reserves and our historical operating data for the years shown below. Estimated net proved reserves are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December of the respective year in accordance with SEC guidelines. For additional information regarding our estimated proved reserves, please read *Business* under Part I, Item 1 and *Properties* under Part I, Item 2 of this Form 10-K. The selected historical operating data set forth below should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 and with *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K.

	December 31,				
	2015	2014	2013	2012	2011
Reserve Data: (1)					
Estimated net proved reserves					
Oil (MMBbls)	35.5	61.7	58.5	54.8	51.4
NGLs (MMBbls)	6.6	15.8	15.9	15.2	17.1
Natural Gas (Bcf)	205.4	254.9	259.9	285.1	289.7
Total barrel equivalents (MMBoe)	76.4	120.0	117.7	117.5	116.9
Total natural gas equivalents (Bcfe)	458.1	720.0	705.9	705.1	701.1
Proved developed producing (MMBoe)	57.6	68.7	60.6	62.6	54.3
Proved developed non-producing (MMBoe) (2)	11.4	14.6	25.5	24.3	22.1
Total proved developed (MMBoe)	69.0	83.3	86.1	86.9	76.4
Proved undeveloped (MMBoe)	7.4	36.7	31.6	30.6	40.5
Proved developed reserves as %	90.3%	69.4%	73.2%	74.0%	65.4%
Reserve additions (reductions) (MMBoe):					
Revisions (3)	(12.7)	4.1	(3.9)	(4.7)	8.6
Extensions and discoveries	4.1	9.7	20.2	15.8	5.3
Purchases of minerals in place	1.0	6.1	2.4	7.0	39.0
Sales of minerals in place (4)	(19.0)	—	(0.5)	(0.4)	—
Production	(17.0)	(17.6)	(18.0)	(17.1)	(16.9)
Net reserve additions (reductions)	(43.6)	2.3	0.2	0.6	36.0

- (1) The conversions to barrels of oil equivalent and cubic feet equivalent were determined using the energy equivalency ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price on an equivalent basis for oil, NGLs and natural gas may differ significantly.
- (2) Approximately 1.4 MMBoe and 1.5 MMBoe of reserves as of December 31, 2013 and 2012, respectively, were shut in at our Mississippi Canyon 506 field (Wrigley) due to a platform and pipeline outage.
- (3) Revisions include changes due to price estimated for reserves held at year-end for each year presented. Revisions in 2015 also include revisions related to the Yellow Rose field up to the date of the sale.
- (4) In 2015, related primarily to the sale of the Yellow Rose field in October 2015.

Volume measurements:

MMBbls – million barrels of crude oil, condensate or NGLs

MMBoe – million barrels of oil equivalent

Bcf – billion cubic feet

Bcfe – billion cubic feet of gas equivalent

	Year Ended December 31,				
	2015	2014	2013 ⁽¹⁾	2012	2011
Operating: (2)					
Net sales:					
Oil (MBbls)	7,751	7,176	7,018	6,033	6,073
NGLs (MBbls)	1,604	2,112	2,091	2,129	1,892
Oil and NGLs (MBbls)	9,355	9,288	9,110	8,163	7,964
Natural gas (MMcf)	46,163	50,088	53,257	53,825	53,743
Total oil equivalent (MBoe)	17,049	17,636	17,986	17,133	16,921
Total natural gas equivalents (MMcfe)	102,294	105,815	107,915	102,800	101,528
Average daily equivalent sales (Boe/day)	46,709	48,317	49,276	46,813	46,360
Average daily equivalent sales (Mcf/day)	280,256	289,904	295,657	280,875	278,158
Average realized sales prices:					
Oil (\$/Bbl)	\$ 45.05	\$ 90.96	\$ 102.44	\$ 104.35	\$ 105.92
NGLs (\$/Bbl)	17.25	34.49	35.07	39.75	55.81
Oil and NGLs (\$/Bbl)	40.28	78.13	86.97	87.50	94.02
Natural gas (\$/Mcf)	2.67	4.35	3.55	2.94	4.12
Oil equivalent (\$/Boe)	29.34	53.49	54.58	50.93	57.32
Natural gas equivalent (\$/Mcfe)	4.89	8.92	9.10	8.49	9.55
Average per Boe (\$/Boe):					
Lease operating expenses	\$ 11.31	\$ 15.01	\$ 15.06	\$ 13.56	\$ 12.95
Gathering and transportation	1.01	1.14	0.95	0.85	1.01
Production costs	12.32	16.15	16.01	14.41	13.96
Production taxes	0.17	0.42	0.42	0.36	0.24
DD&A	23.11	28.98	25.10	20.79	19.43
General and administrative expenses	4.29	4.93	4.55	4.79	4.39
	<u>\$ 39.89</u>	<u>\$ 50.48</u>	<u>\$ 46.08</u>	<u>\$ 40.35</u>	<u>\$ 38.02</u>
Average per Mcfe (\$/Mcfe):					
Lease operating expenses	\$ 1.88	\$ 2.50	\$ 2.51	\$ 2.26	\$ 2.16
Gathering and transportation	0.17	0.19	0.16	0.14	0.17
Production costs	2.05	2.69	2.67	2.40	2.33
Production taxes	0.03	0.07	0.07	0.06	0.04
DD&A	3.85	4.83	4.18	3.47	3.24
General and administrative expenses	0.71	0.82	0.76	0.80	0.73
	<u>\$ 6.64</u>	<u>\$ 8.41</u>	<u>\$ 7.68</u>	<u>\$ 6.73</u>	<u>\$ 6.34</u>
Wells drilled (gross):					
Offshore	5	6	6	5	8
Onshore	5	33	40	77	40
Productive wells drilled (gross):					
Offshore	5	6	5	4	8
Onshore	5	33	40	77	39

- (1) In January 2014, we identified that we had been receiving an erroneous MMBtu conversion factor from a third party that had the effect of understating natural gas production at our Viosca Knoll 783 field (Tahoe). The incorrect conversion factor had been used on all natural gas production from the field since we acquired it in 2011. The use of the incorrect conversion factor did not affect revenues, operating cash flows or royalty payments to the federal government but did impact reported natural gas production and the calculation of depletion expense. We performed an analysis of the information, assessing both quantitative and qualitative factors, and determined that the impact on our net income reported for prior annual periods, as well as the impact to our earnings trend, was not material to 2011 and 2012 results and thus the adjustment was recognized in 2013. The results for 2013 reflect a one-time increase in production of 1.9 Bcf in natural gas (with no corresponding increase in revenues) by using the correct conversion factor for the annual periods of 2011 and 2012. Excluding the cumulative effect of the volumes adjustments related to 2011 and 2012, total production for 2013 would have been 106.0 Bcfe or 290.5 MMcfe per day and our combined average realized sales price would have been \$9.26 per Mcfe.
- (2) The conversions to barrels of oil equivalent and cubic feet equivalent were determined using the energy equivalency ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price on an equivalent basis for oil, NGLs and natural gas may differ significantly.

Volume measurements:

Bbl – barrel

Boe – barrel of oil equivalent

MBbls – thousand barrels for crude oil, condensate or NGLs

MBoe – thousand barrels of oil equivalent

Mcf – thousand cubic feet

MMcf – million cubic feet

MMcfe – million cubic feet equivalent

DD&A - depreciation, depletion, amortization and accretion

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this Form 10-K, particularly in *Risk Factors* under Part I, Item 1A in this Form 10-K.

Overview

We are an independent oil and natural gas producer with operations offshore in the Gulf of Mexico. We have grown through acquisitions, exploration and development and currently hold working interests in approximately 54 offshore fields in federal and state waters (50 producing and four fields capable of producing). We currently have under lease approximately 900,000 gross acres, with approximately 550,000 gross acres on the shelf and approximately 350,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate offshore. We own interests in approximately 200 offshore structures, 137 of which are located in fields that we operate. Our interest in fields, leases, structures and equipment are primarily owned by the parent company, W&T Offshore, Inc. and our wholly-owned subsidiary, W & T Energy VI, LLC.

In managing our business, we are focused on maintaining and growing production and reserves in a profitable and prudent manner. We have historically grown 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. In light of the continued depressed commodity pricing conditions that commenced in the second half of 2014 and assuming such conditions continue throughout 2016, we are managing our business in 2016 by significantly postponing our drilling program with a goal of having 2016 production levels near our 2015 levels.

In October 15, 2015, we sold our interests in the Yellow Rose onshore field in the Permian Basin to Ajax. Our interest in the field covered approximately 25,800 net acres. In connection with the sale, we retained a non-expense bearing ORRI in production from the working interests sold, which percentage varies on a sliding scale from one percent for each month that the prompt month NYMEX trading price for light sweet crude oil is at or below \$70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than \$90.00 per barrel. Internal estimates of proved reserves at the date of the sale were 19.0 MMBoe, consisting of approximately 71% oil, 11% NGL and 18% natural gas. Including adjustments from an effective date of January 1, 2015, the adjusted sales price was \$372.9 million and the buyer assumed the ARO associated with our interests in the Yellow Rose field, which we had estimated at \$6.9 million at the time of the sale. We used a portion of the proceeds of the sale to repay all the outstanding borrowings under our revolving bank credit facility, while the remaining balance of approximately \$100 million was added to available cash.

In September 2014, we acquired an additional ownership interest in the Fairway Field (Mobile Bay blocks 113 and 132) located in Alabama state waters and the associated Yellowhammer gas processing plant, which increased our ownership interest from 64.3% to 100%. Including adjustments from an effective date of July 1, 2014, the adjusted purchase price was \$17.4 million and we assumed the additional ARO associated with the increased ownership interest in Fairway, which we have estimated to be \$6.1 million. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

In May 2014, we acquired from Woodside certain oil and gas leasehold interests in the Gulf of Mexico. The Woodside Properties consisted of a 20% non-operated working interest in the producing Neptune field (deepwater Atwater Valley blocks 574, 575 and 618), along with an interest in the Neptune tension-leg platform, associated production facilities and various interests in 24 other deepwater lease blocks. Including adjustments from an effective date of November 1, 2013, the adjusted purchase price was \$54.8 million and we assumed the ARO associated with the Woodside Properties, which we have estimated to be \$11.3 million. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

In November and December 2013, we acquired from Callon certain oil and gas leasehold interests in the Gulf of Mexico. The Callon Properties consisted of a 15% non-operated working interest in the Medusa field (deepwater Mississippi Canyon blocks 538 and 582), interest in associated production facilities and various interests in other non-operated fields. Including adjustments from an effective date of July 1, 2013, the adjusted purchase price was \$83.0 million and we assumed the ARO associated with the Callon Properties, which we have estimated to be \$4.2 million. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

See *Financial Statements and Supplementary Data – Note 2 – Acquisitions and Divestitures* under Part II, Item 8 in this Form 10-K for additional information on acquisitions and divestitures.

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 2015 were comprised of approximately 46% oil and condensate, 9% NGLs and 45% natural gas, determined using the energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs. The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices per Mcfe for crude oil, NGLs and natural gas may differ significantly. For 2015, our combined total production of oil, NGLs and natural gas was 3% below 2014, as we had new production from recently drilled wells and acquisitions, partially offset by natural production declines, divestitures, various pipeline outages, platform outages and maintenance shut-ins offshore. During 2014, sales volumes also benefited from new wells that were brought on line along with production from acquisitions and were negatively impacted by natural production declines, various pipeline outages, maintenance issues and storms.

Our realized sales prices received for our crude oil, NGLs and natural gas production are affected by not only domestic production activities and political issues, but more importantly, international events, including both geopolitical and economic events. During 2015, crude oil, NGL, and natural gas realized prices were significantly below prior year prices, and the realized prices for all three commodities were the lowest in the fourth quarter of 2015 compared to the prior three quarters of 2015. Thus far in 2016, prices have fallen even further. Partially offsetting the declining sales prices has been a reduction in the cost of supplier goods and services in 2015 compared to 2014, but these have not decreased as quickly and dramatically as the price of the commodities that we sell; therefore, margins have deteriorated significantly in 2015 along with total cash flows. The current market imbalance is predominantly supply driven caused by a number of issues that are described below.

The U.S. Energy Information Administration's ("EIA") data estimates the worldwide supply of crude oil and other petroleum liquids outpaced consumption in 2015 by 1.9 million barrels per day in addition to an oversupply in 2014 by 0.8 million barrels per day. For 2016, EIA forecasts crude oil supply being above consumption by approximately 0.7 million per day. For 2017, EIA forecast supply and consumption to be relatively in balance. Even if a balance between supply and demand is achieved, the accumulated excess inventory will likely provide a continual drag on a price recovery well past such balancing period. This oversupply and high inventory levels is expected to keep downward pressure on prices, which have continued to fall since year-end 2015 to the lowest levels since 2003. The EIA forecasts the first draw on global inventories occurring in the third quarter of 2017. Worldwide crude oil supply growth in 2015 from 2014 was estimated at 2.6%, while consumption growth was estimated at 1.4%. The increases in production were primarily from the U.S. and from within OPEC, primarily with Iraq and Saudi Arabia having the largest increases within OPEC. Per news sources, Saudi Arabia reached an agreement with Russia to freeze oil production at January 2016 levels, but did not agree to production decreases and such agreement is not expected to have an impact on the oversupply situation. The agreement is expected to be rejected by Iran and Iraq as it would limit their production in the near future. Many countries, such as Russia, Iraq, Iran and Venezuela, have economies that are highly or solely dependent on oil revenues and do not have significant cash reserves like Saudi Arabia; therefore, production reductions from these countries is not expected. Due to recent events and the expectations of having economic sanctions lifted, Iran is expected to market its crude oil freely to world-wide markets in 2016, which is expected to result in increased production in 2016.

Many U. S. producers substantially reduced capital expenditures in 2015 compared to 2014 and the number of drilling rigs searching for oil and gas have fallen dramatically (discussed below), EIA estimates U.S. petroleum and other liquids production increased in 2015 despite the reduced capital spending levels. EIA projects capital spending levels to decrease further in 2016, yet still not affect worldwide production levels in a meaningful manner, with OPEC increases offsetting non-OPEC decreases, of which are primarily decreases projected for the U.S. EIA estimates U.S. petroleum and other liquids production for 2014, 2015, 2016 and 2017 to be 14.1, 15.0, 14.6 and 14.6 million barrels per day, respectively, and estimates Canada's petroleum and other liquids production for 2014, 2015, 2016 and 2017 to be 4.4, 4.5, 4.6 and 4.6 million barrels per day, respectively. In addition, the strength in the U.S. dollar relative to other currencies continues to have a very negative impact on crude pricing in most parts of the world. Because all barrels are traded in U.S. dollars, as the U.S. dollar gains strength, crude prices are lower in U.S. dollars but are more expensive in other currencies.

EIA estimates world-wide consumption for petroleum and other liquids grew in 2015 over 2014 by 1.3 million barrels per day (1.4%) and projects year-over-year growth in 2016 and 2017 of 1.5%. Geographically, growth estimates are fairly diverse with China expected to have the largest increases. Eurasia and Europe had decreased consumption in 2015, with Eurasia consumption expected to be flat over the next two years and Europe expected to grow year over year in 2016 and 2017.

In addition to U.S. crude oil production, another factor affecting the price of domestic crude oil is the ability to get production to market. Over the past few years, the infrastructure (both pipeline and rail) to transport crude oil within the United States has seen a major and rapid change. A number of pipelines have been built and completed, reversed flowed, or expanded to move crude oil from Cushing, Oklahoma (a major crude oil storage hub) primarily to the U.S. Gulf Coast but also to the Midwest as well. Transportation capacity has also been added in major producing regions, like the Permian Basin, to move crude oil to the U.S. Gulf Coast rather than to Cushing. Rail receiving capacity also expanded on the East Coast, and to some extent on the U.S. Gulf Coast. In late 2015, Congress lifted the ban on shipping U.S. crude outside of North America. These events have helped decrease the spread between Brent and WTI, which fell to an average of \$3.66 per barrel in 2015 compared to an average \$5.72 per barrel in 2014 and over \$10.00 per barrel in 2013. Thus far in 2016, Brent has at times traded below WTI and current market indications are that Brent will continue to trade near parity to WTI.

During 2015, our average realized crude oil sales price was \$45.05, down from \$90.96 per barrel (50.5% lower) for 2014. The two primary benchmarks reported upon are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged \$48.66 per barrel for 2015, down from \$93.17 per barrel (47.8% lower) for 2014. Brent crude average oil prices decreased to \$52.32 per barrel for 2015, down from \$98.97 per barrel (47.1% lower) for 2014. WTI and Brent average crude oil prices in the fourth quarter of 2015 were lower than the third quarter of 2015 presenting a downward trend in crude oil prices. Our average realized crude oil sales price percentage decrease for 2015 approximately mirrored the benchmarks, but differs due to premiums or discounts (referred to as differentials), volume weighting and other factors. Over 90% of our oil was produced offshore in 2015 in the Gulf of Mexico and is characterized as Light Louisiana Sweet ("LLS"), Heavy Louisiana Sweet ("HLS"), Poseidon and others. WTI is frequently used to value domestically produced crude oil, and the majority of our oil production is priced using the spot price for WTI as a base price, then adjusted for the type and quality of crude oil and other factors. The differentials for our offshore crude oil have also experienced volatility. For example, the monthly average differentials of WTI versus LLS, HLS and Poseidon for 2015 were a positive \$3.72 and \$2.76, and a negative \$1.04 per barrel, respectively. This compares to a positive \$3.88 and \$3.52, and a negative \$1.20 per barrel, respectively, for 2014. Variations in these differentials between quarters have been over \$3.00 per barrel.

An EIA report issued in early January 2016 projected WTI crude oil prices for 2016 and 2017 at \$38.54 per barrel and \$47.00 per barrel, respectively, and Brent crude oil prices for 2016 and 2017 at \$40.15 per barrel and \$50.00, respectively. An EIA report issued in February 2016 revised price projections downward for 2016, forecasting WTI and Brent to be at parity and having averages prices of \$38.00 per barrel and \$50.00 per barrel in 2016 and 2017, respectively.

During 2015, our average realized NGLs sales price decreased 50.0% compared to 2014. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During 2015, average prices for domestic ethane decreased 35% and average domestic propane prices decreased 57% from 2014. Average price decreases for other domestic NGLs were approximately 50%. The price changes were reflective of the price changes for crude oil and natural gas. Production of NGLs continued to increase in 2015 causing re-injection of ethane back into the natural gas stream. Propane inventories are at all-time highs dating back to 1993 when EIA began collecting such inventory data. Propane inventories at the end of 2015 were 25% higher than the same period in 2014. New “rich gas” processing capacity added in the fourth quarter of 2014 has increased NGL extraction capability, which has added additional NGLs to an already oversupplied market. From a historical perspective, NGL production from domestic gas plants has increased over 70% from 2009 levels (from 1.9 million barrels per day to 3.3 million barrels per day). As long as U.S. crude oil and natural gas production remain high and the price ratio of crude oil to natural gas remains wide (as measured on a six to one energy equivalency), the production of NGLs may continue to be high relative to historical norms, which would in turn suggest continued weak prices, or possibly further price reductions, especially for the prices of ethane and propane. Many natural gas processing facilities have been and will likely continue re-injecting ethane back into the natural gas stream after processing due to insufficient ethane demand, which negatively impacts production and natural gas prices. Once propane is extracted from the natural gas stream, it is not re-injected and is sold as a separate component. As propane inventories build with no offsetting increase in demand, propane prices are expected to continue to be weak or weaken further.

During 2015, our average realized natural gas sales price decreased 38.6% compared to 2014. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 40.0% lower in 2015 from 2014. Natural gas prices are more affected by domestic issues (as compared to crude oil prices), such as weather (particularly extreme heat or cold), supply, local demand issues, other fuel competition (coal) and domestic economic conditions, and they have historically been subject to substantial fluctuation. However, with the surplus of natural gas that has plagued the industry since 2012, natural gas prices have been weak and the fluctuations in prices have been limited to the lower end of the price range. The U.S. natural gas inventories at the end of December 2015 were 16% higher than the same period last year and were 15% above the previous five-year average for this time of the year. For 2015, supply increased 3.5% and consumption increased 3.0% over 2014. Consumption increases came from higher electric power usage, while residential and commercial usage was lower. EIA projects inventories at the end of heating season (March 2016) to be 38% above the level at the same time last year.

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

EIA projects natural gas prices to be flat for 2016 compared to 2015 and increase in 2017. EIA estimates natural gas prices (Henry Hub spot price) for the full year 2015, 2016 and 2017 at \$2.71, 2.73 and \$3.32 per Mcf, respectively. U.S. production is projected to be higher in 2016 and 2017 by 1% year over year, which will continue to exert downward pressure on prices. Natural gas usage for power generation is expected to be around 32% in 2016 and 2017, compared to 33% in 2015 and 27% in 2014 due to lower natural gas prices compared to coal and new Federal regulations related to coal usage.

During 2015, the number of rigs drilling for oil and natural gas in the U.S. has declined significantly from 2014 levels due to lower crude oil and natural gas prices. According to Baker Hughes, the oil rig count at the end of 2014 was 1,482 and at the end of 2015 was 536, a decrease of 64% and a five-year low. The U.S. natural gas rig count at the end of 2014 was 328 and at the end of 2015 was 162, a decrease of 51% from year end 2014 and a 28-year low (the extent of data provided by Baker Hughes). In the Gulf of Mexico, there were 54 rigs (42 oil and 12 natural gas) at the end of 2014. As of the end of 2015, there were 25 rigs (20 oil and five natural gas), a decrease of 54% from year end 2014. The majority of rigs in the Gulf of Mexico are currently “floaters” rather than jack-up rigs.

As required by the full cost accounting rules, we performed our ceiling test calculation during 2015 using the SEC pricing guidelines, which require using the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price adjusted for price differentials. We are required to perform the ceiling test calculation at the end of each quarter. The average price using the SEC required methodology at December 31, 2015 was \$46.79 per barrel for WTI crude oil and \$2.59 per MMBtu for Henry Hub natural gas before adjustments. Due to the decrease in the 12-month average price for both crude oil and natural gas, we recorded ceiling test write-downs of the carrying value of our oil and natural gas properties in each quarter of 2015, including \$32.4 million in the fourth quarter of 2015 and totaling \$987.2 million for the full year of 2015. Incurrence of further write downs is dependent primarily on the price of crude oil and natural gas, but also is affected by quantities of proved reserves, the cost of future development costs and the future lease operating costs.

At this time, we expect to incur a further ceiling test impairment write-down in the first quarter of 2016 assuming commodities prices do not increase dramatically. While it is difficult to project future impairment write-downs in light of numerous variables involved, the following price sensitivity calculation using basic assumptions is provided to illustrate the impact of lower commodities pricing on impairment charges and proved reserves volumes. Pro-forma 12-month average prices were determined by using the January 1, 2016 and February 1, 2016 benchmark commodities prices of \$33.50 and \$28.00 per barrel for WTI crude oil and \$2.31 and \$2.26 per MMBtu for Henry Hub natural gas, respectively (before adjustments), then using February 1, 2016 prices as a proxy for March 1, 2016 prices and removing the first quarter 2015 prices from the 12-month average, we calculated that the benchmark 12-month average prices would decrease to \$42.52 per barrel for WTI crude oil and \$2.45 per MMBtu for Henry Hub natural gas (before adjustments). If such pro-forma pricing was used in our PV-10 calculations of reserves at December 31, 2015, and assuming no other changes, our ceiling test impairment write-down for the year 2015 would have increased by \$137.3 million to \$1,124.5 million

Using a pro forma 12-month average commodity prices computed as described in the previous paragraph, our proved reserves would have decreased by approximately 0.9 MMBoe. This is as a result of the loss of one of our offshore proved undeveloped locations, which would not be economically producible at such prices, and some fields would experience a shortened time horizon. The foregoing calculation was made without regard to additions or other further revisions to proved reserves estimated at December 31, 2015 other than as a result of such pricing changes.

See *Properties – Proved Reserves* under Part I, Item 2; *Selected Financial Data* under Part II, Item 6 and *Financial Statements and Supplementary Data – Note 21 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K for additional information on our proved reserves.

During October 2015, we entered into an amendment to our Credit Agreement, which primarily (i) amended certain covenants related to financial ratios, (ii) amended certain limitations on distributions, redemptions and prepayments of indebtedness and (iii) revised margins which increased interest rates. Effective October 30, 2015, the borrowing base was set at \$350 million subject to the next redetermination scheduled for April 2016. During 2015, we entered into the 9.00% Term Loan, with the net proceeds used to pay down a portion of the borrowings outstanding on the revolving bank credit facility. After the sale of the Yellow Rose field, proceeds were used to pay down the outstanding balance on the revolving bank credit facility and the remainder was added to available cash.

As of December 31, 2015, we had \$85.4 million of available cash and we had no borrowings outstanding under the Credit Agreement, which matures in November 2018. Borrowings outstanding under the Credit Agreement subsequent to December 31, 2015 are described below. The 8.50% Senior Notes mature in June 2019 and the 9.00% Term Loan matures in May 2020. See *Liquidity and Capital Resources* in this Item 7 and *Financial Statements and Supplementary Data – Note 7 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information

The significant reductions in crude oil and natural gas pricing commencing in the second half 2014 have adversely impacted the Company's financial strength and have resulted in the Company's inability to meet the relevant financial strength and reliability criteria set forth in the NTL #2008-N07. Prior to 2015, we were partially exempt from providing such financial assurances under our corporate structure. As substantially all of our operations are now subject to supplemental bonding, we had discussions with the BOEM during 2015. In February and March 2016, we received several demands from the BOEM ordering the Company to secure financial assurances in the form of additional surety bonds in the aggregate of \$260.8 million, with amounts specified with respect to certain designated leases. The bonds are to be secured on or before March 29, 2016. As of the date of filing this Form 10-K, we have not obtained these additional supplemental bonds, or acceptable replacement collateral or other financial assurances. Also in February 2016, we borrowed \$340 million on our revolving bank credit facility for liquidity purposes, but we may be required to repay a portion of our outstanding borrowings if our borrowing base under the Credit Agreement is reduced. Our current borrowing base is in the process of being redetermined by our lenders, and we expect such review could result in a reduction of our borrowing base. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base, such excess or deficiency is required to be repaid within 90 days in three equal monthly payments. See *Risk Factors – We may be unable to provide the financial assurances demanded by the BOEM to cover our lease decommissioning obligations in the amounts and under the time periods required by the BOEM. If extensions and modifications to the BOEM's current or future demands are needed and cannot be obtained, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases. – and - The borrowing base under our Credit Agreement may be reduced by our lenders and we are required to repay borrowings that exceed the borrowing base within 90 days in three equal monthly payments. –* under Part I, Item 1A and *Financial Statements and Supplementary Data – Note 20 – Subsequent Events* under Part II, Item 8 in this Form 10-K for additional information.

Many changes in laws, regulations, guidance, interpretations and policy continue to be proposed and issued in our industry. At this time, we are unable to assess the potential impact as clarification is needed for items within the proposals.

Due to the continued deterioration of commodity prices and the outlook for the remainder of 2016, we have set our 2016 capital expenditure budget at \$15 million. This is a significant reduction from our 2015 and 2014 incurred capital expenditures of \$231 million and \$630 million, respectively. We have the flexibility to make this reduction to our 2016 capital expenditure budget because we have no long term rig commitments and no pressure from partners to drill or complete a well. Moreover, we expect our deepwater projects completed in 2015, combined with new production from our Ewing Bank 910 A-8 well will help with 2016 production levels. However, unplanned downtime, pipeline maintenance, and well performance are factors leading to lower estimated production in 2016 from 2015. We do not expect to lose drilling opportunities at this spending level and have no significant lease expiration issues in 2016. In addition, our plans include spending \$84 million in 2016 for ARO, which is an increase from \$33 million spent on ARO in 2015. We continue to closely monitor current and forecasted prices to assess if changes are needed to our plans. See *Risk Factors* under Part I, Item 1A in this Form 10-K for additional information.

Our operating costs in 2015 included the expense of operating our wells, platforms and other infrastructure primarily in the Gulf of Mexico and Texas, and transporting our production to the points of sale. With the sale of the Yellow Rose field in October 2015, our oil and gas properties are entirely in the Gulf of Mexico. Our operating costs are generally comprised of several components, including direct operating costs, repairs and maintenance, gathering and transportation costs, production taxes, insurance premiums, workover costs and ad valorem taxes. Our operating costs depend in part on the type of commodity produced, the level of workover activity and the geographical location of the properties. Workover costs can vary significantly from year to year depending on the level of activity (either required or desired) and type of equipment used. In those instances where a drilling rig is required as opposed to some other type of intervention vessel or equipment, the costs tend to be much higher and require more time.

In recent years, we have operated or participated in wells near the outer edge of the continental shelf and in the deepwater of the Gulf of Mexico. To the extent we continue expanding deepwater operations, our operating costs may increase, especially as we find and produce more crude oil rather than natural gas. While each field can present operating problems that can add to the costs of operating a field, the production costs of a field are generally directly proportional to the number of production platforms built in the field. As technologies have improved, oil and natural gas can be produced from larger acreage areas using a single platform, which may reduce the operating costs associated with future development projects.

Our offshore operations are exposed to potential damage from hurricanes and we obtain insurance to reduce, but not totally mitigate, our financial exposure risk. See *Liquidity and Capital Resources - Hurricane Remediation, Insurance Claims and Insurance Coverage* under this Item 7 and *Financial Statements and Supplementary Data – Note 18 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information.

Applicable environmental regulations require us to remove our platforms after production has ceased, to plug and abandon all wells and to remediate any environmental damage our operations may have caused. These types of activities are collectively referred to as decommissioning or ARO. The costs associated with our ARO generally increase as we drill wells in deeper parts of the continental shelf and in the deepwater. We generally do not pre-fund our ARO. We estimated the present value of our liability related to our ARO at \$378.3 million as of December 31, 2015, of which \$84.3 million is estimated to be spent during 2016. Inherent in the present value calculation of our liability are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and expenditure, and changes in the legal, regulatory, environmental and political environments. Actual expenditures for ARO could vary significantly from these estimates. Prior to 2015, we have seen upward revisions in costs to do this work partly due to significant changes in the regulatory requirements and partly due to the escalation in the cost of goods and services required to do the work. During 2015, some of the plug and abandonment service costs were lower, some stayed relatively constant, and some increased from scope and regulatory interpretation changes. Overall, service costs related to plugging and abandonment were relatively the same as in 2014. During 2015, our lease operating expenses decreased approximately 25% in 2015 on a per BOE basis. At current commodity prices, we expect that costs for decommissioning and the related ARO liability will decline as well.

Many changes in laws, regulations, guidance, interpretations and policy continue to be proposed and issued in our industry. The process for obtaining offshore drilling permits, especially deepwater drilling permits, has expanded and lengthened in the past few years. The most significant regulatory changes in recent years are regulations related to potential environmental impacts, spill response documentation, compliance reviews, operator practices related to safety and implementing a safety and environmental management system. The new regulations and increased review process increases the time to obtain drilling permits and increases the cost of operations. Also, the regulations have changed related to plugging and abandonment of offshore wells and related infrastructure considerably, driving up both the time and cost to perform the work. As these new regulations and guidance continue to evolve, we cannot estimate the cost and impact to our business at this time. See *Regulation* under Part I, Item 1 in this Form 10-K for additional information.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Revenues. Total revenues decreased \$441.4 million, or 46.5%, to \$507.3 million in 2015 compared to 2014. Oil revenues decreased \$303.6 million, or 46.5%, NGLs revenues decreased \$45.2 million, or 62.0%, natural gas revenues decreased \$94.4 million, or 43.3%, and other revenues increased \$1.7 million. The oil revenue decrease was attributable to a 50.5% per barrel decrease in the average realized sales price to \$45.05 per barrel in 2015 from \$90.96 per barrel in 2014, partially offset by an 8.0% increase in sales volumes. The NGLs revenue decrease was attributable to a 50.0% decrease in the average realized sales price to \$17.25 per barrel in 2015 from \$34.49 per barrel in 2014 and a decrease of 24.1% in sales volumes. The decrease in natural gas revenue was attributable to a 38.6% decrease in the average realized natural gas sales price to \$2.67 per Mcf in 2015 from \$4.35 per Mcf for 2014 and a 7.8% decrease in sales volumes. We experienced increases in production at the Ship Shoal field 349 field (Mahogany); Mississippi Canyon 538/582 field (Medusa); Mississippi Canyon 506 (Wrigley) field; Atwater Valley 575 field (Neptune); Brazos A133 field (partially due to the acquisition of an additional working interest); and Mississippi Canyon 782 (Dantzler) and Mississippi Canyon 698 (Big Bend), which began production in the fourth quarter of 2015. Production was negatively impacted for all commodities from natural production declines, production deferrals affecting various fields and the divestiture of the Yellow Rose field. We estimate production deferrals were 2.4 MMBoe during 2015 due primarily to pipeline, third party and well issues. Some portion of this deferred production will not be recovered in the future as certain wells were sold or abandoned. During 2014, estimated production deferrals were 2.6 MMBoe.

Revenues from oil and liquids as a percent of our total revenues were 74.3% for 2015 compared to 76.5% for 2014. NGLs realized sales prices as a percent of crude oil realized prices increased to 38.3% for 2015 compared to 37.9% for 2014.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased \$72.0 million, or 27.2%, to \$192.8 million in 2015 compared to 2014. On a per Boe basis, lease operating expenses decreased to \$11.31 per Boe during 2015 compared to \$15.01 per Boe during 2014. On a component basis, workover expense decreased \$26.0 million, base lease operating expenses decreased \$24.5 million, facilities maintenance decreased \$17.3 million and insurance premiums decreased \$4.9 million. The decrease in workover costs was primarily due reductions in onshore activity and offshore activity at High Island 111 in 2014. Base lease operating expenses decreased primarily due to lower cost from service providers, less onshore downhole well work and the sale of the Yellow Rose field, partially offset by increases from acquisitions, lower production handling fees, expenses related to our new deepwater fields at Dantzler and Big Bend, and expenses related to our new well at Ewing Banks 910.

Production taxes. Production taxes decreased to \$3.0 million, or 62.2%, during 2015 compared to \$7.9 million in 2014 primarily due to lower commodity prices, lower onshore volumes and the sale of the Yellow Rose field. Currently, production taxes are not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes, while onshore and state water operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased to \$17.2 million, or 13.4%, in 2015 compared to \$19.8 million in 2014 primarily due to reductions related to transactions with the Terrebonne gas processing plant.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to \$23.11 per Boe for 2015 from \$28.98 per Boe for 2014. On a nominal basis, DD&A decreased to \$394.1 million, or 22.9%, for 2015 from \$511.1 million in 2014. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during the first three quarters of 2015 (the fourth quarter ceiling test write-down will affect the DD&A rate starting with the first quarter of 2016) and lower capital expenditures in relation to DD&A expense, which lowers the full-cost pool subject to DD&A. In addition, the proceeds from the sale of our Yellow Rose field reduced the full cost pool along with the removal of future development costs associated with the Yellow Rose field reserves. Additional factors affecting the DD&A rate are lower future development costs on remaining reserves and lower proved reserves.

Ceiling test write-down of oil and natural gas properties. For 2015, we recorded a non-cash ceiling test write-down of \$32.4 million in the fourth quarter of 2015 and \$987.2 million for the full year as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down is the result of decreases in prices for all three commodities we sell, which are crude oil, NGLs and natural gas. No ceiling test write-down was recorded in 2014. See *Financial Statements and Supplementary Data – Note 1 - Basis of Presentation* under Part II, Item 8 in this Form 10-K, which provides a description of the ceiling test limit determination, and above under the section *Overview* in this Item regarding our prospects for a future significant ceiling test write-down and a price sensitivity computation.

General and administrative expenses (“G&A”). G&A decreased to \$73.1 million, or 16.0%, for 2015 from \$87.0 million for 2014 primarily due to decreases in incentive compensation, a significant decrease in the use of contractors and much lower share-based compensation, partially offset by lower billings to joint venture partners, increased costs related to surety bonds, increases in medical claims and recording a contingent provision for proposed fines from the BSEE. G&A on a per BOE basis was \$4.29 Boe for 2015 compared to \$4.93 per Boe for 2014. See *Financial Statements and Supplementary Data – Note 11 – Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 in this Form 10-K for additional information.

Derivative net gain. For 2015, there was a \$14.4 million derivative net gain recorded for derivative contracts for crude oil and natural gas. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015, relating to 2015 and 2016 estimated production. For 2015, the net gain reflects changes in the fair value for all open contracts and for closed contracts. For 2014, the derivative net gain was \$4.0 million and related to derivative contracts for crude oil. During 2014, all open positions expired and closed. See *Financial Statements and Supplementary Data – Note 6 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Interest expense. Interest expense incurred was \$104.6 million in 2015, up from \$86.9 million in 2014. The increase was primarily attributable to increased borrowings and the issuance of the 9.00% Term Loan in May 2015 with an aggregate principal of \$300.0 million and issued at a 1% discount to par. The aggregate principal amount of our 8.50% Senior Notes outstanding was \$900.0 million in both periods. During 2015 and 2014, \$7.3 million and \$8.5 million, respectively, of interest were capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying certain unevaluated properties related to the Yellow Rose field to the full cost pool during the fourth quarter of 2015 and reclassifying certain unevaluated properties during the fourth quarter of 2014.

Other (income) expense, net. For 2015, \$4.7 million of net expense was recorded. During 2015, the borrowing base on the revolving bank credit facility was reduced. The reductions in the borrowing base resulted in proportional reductions in the unamortized debt issuance costs of \$3.2 million related to the revolving bank credit facility. In addition, a net loss on sale of assets of \$1.0 million was recorded primarily related to the sale of computer equipment used for backup processes. For 2014, other net income was \$0.2 million.

Income tax expense. Our income tax benefit for 2015 was \$203.0 million compared to an income tax benefit of \$4.5 million for 2014, with the change attributable primarily to increases in the pre-tax loss for 2015 compared to 2014. Our effective tax rate was 16.3% and differs from the federal statutory rate of 35% primarily due to recording a valuation allowance of \$232.9 million related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. Our effective tax rate for the year 2014 is distorted due to a small pre-tax loss; consequently, our permanent differences have a larger impact on our effective tax rate. See *Financial Statements and Supplementary Data – Note 13 – Income Taxes* under Part II, Item 8 in this Form 10-K for additional information

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Revenues. Total revenues decreased \$35.4 million, or 3.6%, to \$948.7 million in 2014 compared to 2013. Oil revenues decreased \$66.2 million, or 9.2%, NGLs revenues decreased \$0.5 million, or 0.7%, natural gas revenues increased \$28.5 million, or 15.1%, and other revenues increased \$2.8 million. The oil revenue decrease was attributable to an 11.2% per barrel decrease in the average realized sales price to \$90.96 per barrel from \$102.44 in 2013, partially offset by a 2.3% increase in sales volumes. The NGLs revenue decrease was attributable to a 1.7% decrease in the average realized sales price to \$34.49 per barrel in 2014 from \$35.07 per barrel in 2013, partially offset by an increase of 1.0% in sales volumes. The natural gas revenue increase was attributable to a 22.5% increase in the average realized natural gas sales price to \$4.35 per Mcf from \$3.55 per Mcf for 2013, partially offset by a decrease in sales volumes by 6.0%. We experienced increases in production from the A-5 well at Mississippi Canyon 243 (Matterhorn), the A-14 well at Ship Shoal 349 (Mahogany), the return to production of Mississippi Canyon 506 (Wrigley), increases at Fairway due to acquiring the remaining working interest in the field as well as productive well work in the field, new production from both Medusa and Neptune fields, and acquisitions consummated during 2014. Production was negatively impacted for all commodities from natural production declines, production deferrals affecting various fields and the divestitures of certain fields in 2013. The production deferrals were attributable to third-party pipeline outages, platform maintenance, and various operational issues. We estimate production deferrals were 2.6 MMBoe during 2014. Specifically, production at Mississippi Canyon 506 (Wrigley) was deferred as a result of maintenance at the host platform and comprised approximately 17% of the deferred production. The Wrigley field resumed production during 2014. In addition, production from selected wells at Ship Shoal 349 (Mahogany) was deferred due to closure of a pipeline, a rig move and well work and weather was a contributing factor in the first quarter of 2014 for production declines at West Texas and at selected offshore fields. The balance of the deferred production occurred at multiple locations. During 2013, estimated production deferrals were 2.2 MMBoe.

Revenues from oil and liquids as a percent of our total revenues were 76.5% for 2014 compared to 80.5% for 2013. NGLs realized sales prices as a percent of crude oil realized prices increased to 37.9% for 2014 compared to 34.2% for 2013.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, facilities maintenance, decreased \$6.1 million, or 2.2%, to \$264.8 million in 2014 compared to 2013. On a per Boe basis, lease operating expenses decreased to \$15.01 per Boe during 2014 compared to \$15.06 per Boe during 2013. On a component basis, workover expense decreased \$13.2 million, facilities maintenance expense decreased \$4.6 million and insurance premiums decreased \$3.3 million, partially offset by increases in base lease operating expenses of \$15.4 million. The decrease in workover costs was primarily due to workovers at Main Pass 69 and Ship Shoal (Mahogany) occurring in 2013, which were partially offset by workovers at High Island 111 and High Island 129 occurring in 2014 and increased workover costs at Spraberry (Yellow Rose). The decrease in facilities maintenance expense was primarily due to the shutdown for scheduled maintenance at our Yellowhammer plant occurring in 2013. Base lease operating expenses were higher primarily due to new fields acquired in 2014 and 2013, a decrease in fees charged out to a third party at Mississippi Canyon 243 and increases related to new wells at Ship Shoal 349 (Mahogany) and Spraberry (Yellow Rose).

Production taxes. Production taxes increased to \$7.9 million, or 11.2%, during 2014 compared to \$7.1 million in 2013 primarily related to increased production in the state waters of Alabama at our Fairway Field, which was impacted by our increase in ownership effective in September 2014 and increases in overall production at the field. Partially offsetting were decreases in production and sales at our onshore operations. Currently, production taxes are not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes while onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased to \$19.8 million, or 13.2%, in 2014 compared to \$17.5 million in 2013 primarily due to escalation in third-party transportation fees.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to \$28.98 per Boe for 2014 from \$25.10 per Boe for 2013. On a nominal basis, DD&A increased to \$511.1 million, or 13.2%, for 2014 from \$451.5 million in 2013. DD&A on a per Boe and nominal basis increased in part due to increases in the full cost pool from capital expenditures and estimated future development costs. Our focus on expanding deepwater exploration and development necessarily increases costs prior to increasing proved reserves, leading to an increase in the rate.

General and administrative expenses. G&A increased to \$87.0 million, or 6.3%, for 2014 from \$81.9 million for 2013 primarily due to increases in salaries, share-based compensation, contract labor costs and reductions in charge-outs to third-parties, partially offset by lower cash-based incentive compensation. G&A on a per BOE basis was \$4.93 Boe for 2014 compared to \$4.55 per Boe for 2013. See *Financial Statements and Supplementary Data – Note 11 – Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 in this Form 10-K for additional information.

Derivative (gain)/loss. For 2014 and 2013, our derivative positions resulted in a net gain of \$4.0 million and a net loss \$8.5 million, respectively, and related to the change in the fair value of our then open crude oil commodity derivatives positions as a result of changes in crude oil prices. During 2014, all open positions expired and closed. For 2013, the contracts related to production anticipated in both 2013 and 2014 and reflect changes in the fair value for all open contracts recorded currently and for closed contracts. *Financial Statements and Supplementary Data – Note 6 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Interest expense. Interest expense incurred increased to \$86.9 million for 2014 from \$85.6 million for 2013 primarily due to higher balances on our revolving bank credit facility. The aggregate principal amount of our 8.50% Senior Notes outstanding was \$900.0 million during both years. During 2014 and 2013, \$8.5 million and \$10.1 million, respectively, of interest were capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying a portion of our unevaluated properties to the full cost pool during 2014 and during the fourth quarter of 2013. See *Financial Statements and Supplementary Data – Note 7 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information.

Other income, net. For 2014, other income was \$0.2 million. For 2013, other income was \$8.9 million and consisted primarily of funds received in conjunction with a payment to us for an option exercised by a counterparty.

Income tax expense (benefit). Income tax benefit was \$4.5 million for 2014 compared to income tax expense of \$28.8 million for 2013 due to a pre-tax loss in 2014 compared to pre-tax income in 2013. Our effective tax rate for the year 2014 is distorted due to a small pre-tax loss; consequently, our permanent differences have a larger impact on our effective tax rate. Our effective tax rate for 2013 was 35.9% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures and strategic property acquisitions to allow us to replace our oil and natural gas reserves, repay outstanding borrowings, make related interest payments and satisfy our asset retirement obligations. We have funded such activities with cash on hand, net cash provided by operating activities, sales of property, securities offerings and bank borrowings. These sources of liquidity have historically been sufficient to fund our ongoing cash requirements.

Due to the decline of commodity prices that commenced in the second half of 2014, we expect our future revenues, earnings, liquidity and ability to invest in future reserve growth to continue to be negatively impacted. Other potential negative impacts of such price weakness include:

- our ability to meet our financial covenants in future periods;
- recognizing additional ceiling test write-downs of the carrying value of our oil and gas properties;
- reductions in our proved reserves and the estimated value thereof;
- additional supplemental bonding and potential collateral requirements;
- reductions in our borrowing base under the Credit Agreement.

As a result of the potential for these events, we have engaged legal and financial advisors to assist the Board of Directors and our management team to evaluate the strategic alternatives available to us, which may include, among other things, securities offerings and other financing activities, joint ventures and sales of properties. We may also from time to time seek to retire or purchase our outstanding debt through open market or privately negotiated cash purchases or exchange our existing debt for equity securities or debt securities or term loans, which may be secured by a lien on our assets. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. However, no assurances can be given that any of these alternatives will be available in 2016 or in future years.

In addition, these events could impact our ability to comply with the covenants under our Credit Agreement or other debt instruments, which would force us to engage the lenders or bondholders in discussions regarding further amendments or covenant relief. We may have to reduce future cash outlays for capital expenditures and other activities until such time as operating margins improve sufficiently and market conditions recover or stabilize. Realization of any of these events would depend on the longevity and severity of such price weakness.

In February 2016, we borrowed \$340 million on our revolving bank credit facility for liquidity purposes, which was substantially the amount available under the Credit Agreement. After the borrowing, we had approximately \$447 million in cash. Our borrowing base is in the process of being redetermined by our lenders and we expect that a reduction in the borrowing base could result. The borrowing base could be further reduced in the future as a result of the continued impact of low current oil and gas prices and our lenders' outlook for future prices or our failure to replace reserves as a result of constrained capital spending. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base, such excess or deficiency is required to be repaid within 90 days in three equal monthly payments.

In February and March 2016, we received several demands from the BOEM ordering the Company to secure financial assurances in the form of additional surety bonds in the aggregate of \$260.8 million, with amounts specified with respect to certain designated leases and rights of way. The bonds are to be secured on or before March 29, 2016. In addition, pursuant to the terms of our agreements with various sureties under our existing bonding arrangements or under any additional bonding arrangements we may enter into, we may be required to post collateral at any time, on demand, at the surety's discretion. We have received demands for collateral from several of our existing sureties. The collateral we may provide to support surety bond obligations in the future will probably be in the form of cash or letters of credit. As of the date of filing this Form 10-K, we have posted no such collateral in connection with surety bonds and can provide no assurances that we will be able to post such collateral in the future or that we will be able to secure additional surety bonds. See *Financial Statements – Note 7 – Long-Term Debt* and *Note 20 – Subsequent Events* under Part II, Item 8 of this Form 10-K for additional information on our long-term debt and surety bond obligations.

Cash flow and working capital. Net cash provided by operating activities for 2015 was \$132.6 million, compared to \$474.0 million for 2014. Cash flows from operating activities, before changes in working capital and ARO settlements, were \$140.3 million in 2015, a decrease of \$360.5 million compared to 2014. The change in cash flows excluding working capital and ARO settlements was primarily due to lower revenues, partially offset by lower operating costs. Our combined average realized sales price per Boe decreased 45.1%, with lower average realized sales prices of crude oil, NGLs and natural gas. Our combined production of oil, NGLs and natural gas on a Boe basis during 2015 decreased 3.3% from 2014 due to decreases in NGLs and natural gas production, partially offset by increases in oil production.

The changes in working capital and ARO settlements led to a net increase of \$19.1 million in net cash provided by operating activities between 2015 and 2014. The increase was primarily caused by lower settlements of ARO, partially offset by changes in working capital items.

Net cash provided by investing activities during 2015 was \$86.1 million and net cash used in investing activities during 2014 was \$592.5 million. For 2015, the net amount is primarily due to proceeds from the sale of all our onshore interest in the Yellow Rose field, partially offset by net investments in offshore oil and gas properties. There were only minor acquisitions during 2015, which are included with net investments in oil and natural gas properties. Our investments for 2015 were drastically reduced in reaction to the reduction of commodity prices. Investments in oil and natural gas properties on an accrual basis in 2015 were \$230.2 million compared to \$554.4 million in 2014. The majority of expenditures during 2015 related to investments in deepwater projects. For 2014, the net amount represents investments in both offshore and onshore oil and gas properties. Included in 2014 were acquisitions of \$72.2 million comprised primarily of the Woodside Properties and for the additional interest in Fairway.

Net cash used by financing activities was \$156.9 million during 2015 as our total debt was reduced from balances at December 31, 2014. The net cash used in 2015 was primarily attributable to net repayments of all amounts outstanding on the revolving bank credit facility of \$447.0 million, partially offset by the issuance of the 9.00% Term Loan, net of discount of \$297.0 million and debt issuance costs. Net cash provided by financing activities was \$126.4 million during 2014. The net cash provided during 2014 was primarily attributable to net borrowings on our revolving bank credit facility of \$157.0 million, which was partially offset by dividend payments of \$30.3 million.

Credit Agreement and long-term debt. Our revolving bank credit facility is governed under the Credit Agreement. Borrowings at February 29, 2016 were \$340.0 million, which are discussed above. No borrowings were outstanding as of December 31, 2015, and borrowings were \$447.0 million at December 31, 2014. During 2015, the highest borrowings outstanding on the revolving bank credit facility were \$533.0 million. At December 31, 2015 and 2014, \$900.0 million principal amount of our 8.50% Senior Notes were outstanding. At December 31, 2015, \$300.0 million principal amount of our 9.00% Term Loan was outstanding, which was issued during 2015.

The Credit Agreement terminates on November 8, 2018 and interest and fees are payable quarterly in arrears. The 8.50% Senior Notes mature on June 15, 2019 and interest is payable semi-annually in arrears on June 15 and December 15 of each year. The 9.00% Term Loan matures on May 15, 2020 and interest is payable semi-annually in arrears on May 15 and November 15 of each year. See *Financial Statements and Supplementary Data – Note 7 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information about our long-term debt.

We currently have 20 lenders within the revolving bank credit facility, with commitments ranging from \$9.7 million to \$27.0 million for the current borrowing base. While we have not experienced, nor do we anticipate, any difficulties in obtaining funding from any of these lenders at this time, any lack of or delay in funding by members of our banking group could negatively impact our liquidity position.

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 lenders and the Company have the option for an additional redetermination every year. The Credit Agreement contains financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on financial ratios, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement, the 8.50% Senior Notes and the 9.00% Term Loan as of December 31, 2015.

Derivative financial instruments. From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of December 31, 2015, we had outstanding open derivatives for crude oil and natural gas. These derivatives provide downside protection against a portion of our anticipated 2016 production and will provide cash inflows when crude oil or natural gas prices average below \$40.00 per barrel and \$2.25 per MMBtu, respectively, in a month. See *Financial Statements and Supplementary Data – Note 6 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information about our derivatives.

Hurricane remediation, insurance claims and insurance coverage. During 2008, Hurricane Ike caused substantial property damage. Substantially all the costs related to Hurricane Ike have been incurred and we submitted claims under our insurance policies effective at that time, of which \$161.2 million has been collected through December 31, 2015. In June 2014, the Fifth Circuit reversed a lower court's ruling in holding that our Excess Policies cover removal-of-wreck and debris claims arising from Hurricane Ike, even though we exhausted the limits of our Energy Package with non-removal-of-wreck and debris claim. Several of the underwriters have not paid us amounts we claim are due under such Excess Policies in accordance with the Fifth Circuit ruling. We filed a lawsuit in September 2014 against certain underwriters for amounts owed, interest, attorney fees and damages. We subsequently received reimbursement from certain underwriters of the Excess Policies of approximately \$10 million. We believe we are still owed additional reimbursement of removal-of-wreck costs of approximately \$31 million, plus interest, attorney fees and damages, if any. Given the Fifth Circuit's ruling, we expect to be reimbursed and compensated for all these costs, interest, fees and damages. See *Financial Statements and Supplementary Data - Note 18 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information.

We currently carry multiple layers of insurance coverage in our Energy Package covering our operating activities, with higher limits of coverage for higher valued properties and wells. The current policy limits for well control range from \$30.0 million to \$500.0 million depending on the risk profile and contractual requirements. We have \$75.0 million of named windstorm (hurricane and tropical storm) coverage for certain of our offshore properties and wells and an additional \$75.0 million for certain properties and wells at our higher value fields. We have \$50.0 million of named windstorm coverage for our lower value offshore properties for the cost of removal in excess of scheduled ARO amounts. The well control, named windstorm and physical damage coverage is effective until June 1, 2016. A per-occurrence retention amount of \$30.0 million for named windstorm events must be satisfied by us before our insurers will indemnify us for losses and we co-insure 15% of our named windstorm coverage. The risk exposure varies per property and we have exposure for applicable retentions, co-insurance amounts and coverage limits. We also have other smaller per-occurrence retention amounts for various other events. Coverage for pollution causing a negative environmental impact is provided under the well control and named windstorm sections of the policy.

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

Our general and excess liability policies are effective until May 1, 2016 and provide for \$300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. We had a separate builder's risk and liability policy for certain non-operated properties for platforms and drilling operations under construction, which expired in the fourth quarter of 2015 with the completion of the construction. With respect to the Oil Spill Financial Responsibility requirement under the Oil Pollution Act of 1990, we are required to evidence \$150.0 million of financial responsibility to the BSEE. We qualify to self-insure for \$50.0 million of this amount and the remaining \$100.0 million is covered by insurance.

Although we were able to renew our general and excess liability policies, and Energy Package in May and June of 2015, respectively, our insurers may not continue to offer this type and level of coverage to us in the future, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurers will not pay our claims. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

The premiums for the above policies including brokerage fees were \$16.3 million for the May/June 2015 policy renewals compared to \$26.2 million for the expiring policies. The decrease in our premiums effective with the May/June 2015 renewal was primarily attributable to the lower premiums as a result of no named windstorms over the last several years affecting our properties.

Capital expenditures. The level of our investment in oil and natural gas properties changes from time to time depending on numerous factors, including the prices of crude oil, NGLs and natural gas, acquisition opportunities, and the results of our exploration and development activities. The following table presents our capital expenditures for acquisitions, exploration, development and other leasehold costs and our asset retirement obligation settlements:

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Acquisition of additional interest in Fairway (1)	\$ 1,285	\$ 17,407	\$ —
Acquisition of Woodside Properties (1)	214	54,827	—
Acquisition of Callon Properties	—	576	82,424
Exploration (2)	51,768	179,196	198,740
Development (2)	160,500	346,388	308,327
Seismic, capitalized interest, other	16,394	28,218	44,887
Acquisitions and investments in oil and gas property/equipment	<u>\$ 230,161</u>	<u>\$ 626,612</u>	<u>\$ 634,378</u>

(1) The amounts in 2015 represent adjustments to the purchase price for post-effective adjustments.

(2) Reported geographically in the subsequent table.

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

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Conventional shelf	\$ 13,933	\$ 131,215	\$ 143,151
Deepwater	186,579	216,539	143,745
Deep shelf	195	23,615	61,953
Onshore	11,561	154,215	158,218
Exploration and development capital expenditures	<u>\$ 212,268</u>	<u>\$ 525,584</u>	<u>\$ 507,067</u>

The following table sets forth our drilling activity on a gross basis.

	Completed			Non-commercial		
	2015	2014	2013	2015	2014	2013
Offshore - gross wells drills:						
Conventional shelf	—	3	4	—	—	1
Deepwater	5	3	1	—	—	—
Wells operated by W&T	—	4	5	n/a	n/a	n/a
Onshore:						
Gross wells drilled	5	33	40	—	—	—
Wells operated by W&T(1)	—	32	40	n/a	n/a	n/a

(1) The onshore wells were sold during 2015; therefore, no onshore well drilled in 2015 were classified as operated in the table above.

As of December 31, 2015, we were in the process of completing one offshore exploration well at the Ewing Bank 910 field (the EW 0954 A-8 well). At the Ship Shoal 349 field (Mahogany), a well was spud in 2014, but drilling was suspending in January 2015 with the rig stacked at the platform.

See *Properties –Drilling Activity* under Part I, Item 2 of this Form 10-K for a breakdown of exploration and development wells and additional drilling activity information.

See *Properties –Development of Proved Undeveloped Reserves* under Part I, Item 2 of this Form 10-K for a discussion on activity related to proved undeveloped reserves.

We acquired the following leases from the BOEM: two leases (\$0.3 million), five leases (\$2.4 million) and two leases (\$0.5 million) for the years 2015, 2014 and 2013, respectively.

From time to time, we sell various oil and gas properties for a variety of reasons including, change of focus, perception of value and to reduce debt, among other reasons. As previously discussed, in 2015 we sold our interest in the Yellow Rose field for \$372.9 million after adjustments and reduced related ARO for \$6.9 million. In 2014, there were no property sales of significance. In 2013, we sold our working interests in the Green Canyon 60 field, the Green Canyon 19 field, the West Delta area block 29 and, combined with various other transactions and adjustments, produced net cash receipts of \$10.2 million and reduced ARO by \$19.6 million. Also in 2013, we received \$9.1 million in conjunction with a payment to us for an option exercised by a counterparty. See *Financial Statements and Supplementary Data – Note 2 – Acquisitions and Divestitures* under Part II, Item 8 in this Form 10-K for additional information on divestitures.

Capital expenditures. Our initial capital expenditure budget for 2016 was initially set at \$100 million, not including any potential acquisitions, allocated primarily to development. Because of the continued deterioration of commodity prices and the outlook for the remainder of 2016, we have reduced our capital expenditure budget to \$15 million. See the *Overview* section in this Item for additional information.

Income taxes. During 2015, we did not make any income tax payments nor receive any refunds of significance. For 2016, we expect that a substantial portion of our income tax will be deferred and payments, if any, will be primarily related to state taxes. We have \$418.4 million of Federal net operating loss carryforwards (tax basis) available to offset future federal taxable income in 2016 and forward. We also have \$12.1 million of alternative minimum tax credit carryforwards (tax basis) available to be utilized in 2016 and forward. During 2014, we did not make any income tax payments and received \$3.0 million of refunds. During 2013, we made income tax payments of \$3.0 million and received \$59.1 million of refunds. The refunds received in 2013 were primarily attributable to tax loss carrybacks to 2010 and 2011, and refunds of 2012 estimated federal tax payments. As of December 31, 2015, \$9.5 million of the refunds received in 2013 have been accounted for as unrecognized tax benefits.

Dividends. In 2015, we did not pay any dividends as dividend payments have been suspended. In 2014, we paid \$30.3 million in dividends. In 2013, we paid \$58.8 million in dividends, which included a special dividend totaling \$31.8 million and regular dividends of \$27.0 million. Dividends are subject to periodic review of the Company's performance and the current economic environment, applicable debt agreement restrictions and statutory limitations.

Asset retirement obligations. Each year (and often more frequently) we review and revise our ARO estimates. Our ARO at December 31, 2015 and 2014 were \$378.3 million and \$390.6 million, respectively. Our estimate of ARO spending in 2016 is \$84.3 million. In 2015 and 2014, we revised our estimates to account for the increased cost to comply with new and revised regulations including an increase in work scope and interpretation of work scope and also revised cost estimates in line with current market rates. Additionally, during 2015, we revised our estimates of costs anticipated to be charged by service providers for plug and abandonment projects. As these estimates are for work to be performed in the future, and in many case, several years in the future, actual expenditures could be substantially different than our estimates. See Risk Factors – *Our estimates of future asset retirement obligations may vary significantly from period to period and are especially significant because our operations are concentrated in the Gulf of Mexico* under Part I, Item 1A and *Financial Statements and Supplementary Data – Note 5 – Asset Retirement Obligations* under Part II, Item 8 in this 10-K for additional information regarding our ARO.

Contractual obligations. At December 31, 2015, we did not have any capital leases. As of December 31, 2015, we had closed derivative contracts which were receivables to us and we had open derivative contracts which were recorded as assets at fair value; therefore, no amounts for derivatives are included in the table below. Depending on the underlying commodity prices of the contracts at the time of settlement, these derivative contracts could result in payments. The following table summarizes our significant contractual obligations by maturity as of December 31, 2015:

	Payments Due by Period as of December 31, 2015				
	Total	Less than One Year	One to Three Years	Three to Five Years	More Than Five Years
Long-term debt - principal	\$ 1,200.0	\$ —	\$ —	\$ 1,200.0	\$ —
Long-term debt - interest (1)	393.3	105.1	209.5	78.7	—
Drilling rigs	7.0	7.0	—	—	—
Operating leases	12.4	1.6	3.3	3.6	3.9
Asset retirement obligations (2)	378.3	84.3	90.6	66.0	137.4
Other liabilities and commitments (3)	59.0	7.9	15.7	9.7	25.7
Total	\$ 2,050.0	\$ 205.9	\$ 319.1	\$ 1,358.0	\$ 167.0

- (1) Interest on long-term debt is comprised of: (a) interest on our 8.50% Senior Notes, which bear interest at a fixed rate of 8.50%; (b) interest on our 9.00% term loan, which bears a fixed interest rate of 9.00%; and (c) interest on our revolving bank credit facility, estimated using the commitment fee of 0.375% on the unused balance as of December 31, 2015 and estimated fees for letters of credit outstanding as of December 31, 2015. There were no borrowings under our revolving bank credit agreement as of December 31, 2015; therefore, no interest component for borrowings was included in the estimate. Interest was calculated through the stated maturity date of the related debt.
- (2) ARO in the above table is presented on a discounted basis, consistent with the amounts reported on the Consolidated Balance as of December 31, 2015 and are estimates of future payments. Actual payments and the timing of the payments may be significantly different than estimates. All other amounts in the above table are presented on an undiscounted basis.
- (3) Other liabilities and commitments primarily consist of estimated fees for obtaining bonds related to obligations under certain purchase and sale agreements and supplemental bonding for plugging and abandonment on behalf of the BOEM. The amounts are based on current market rates and conditions for these types of bonds and are subject to change. Excluded are potential increases in bond requirements which have not yet been determined. Also excluded are obligations under joint interest arrangements related to commitments that have not yet been incurred. In these instances, we are obligated to pay, according to our interest ownership, a portion of exploration and development costs, operating costs and potentially could be offset by our interest in future revenue from these non-operated properties. These joint interest obligations for future commitments cannot be determined due to the variability of factors involved. See *Financial Statements and Supplementary Data – Note 16 – Commitments* under Part II, Item 8 in this 10-K for additional information.

Inflation and Seasonality

Inflation. For 2015, our realized prices for crude oil decreased 50.5%, NGLs decreased 50.0% and natural gas decreased 38.6% from 2014. These are discussed in the *Overview* section above. Costs measured on a \$/Boe basis (excluding DD&A and ceiling test write-downs) decreased by 22.0% in 2015 compared to 2014. The cost per Boe is impacted by factors other than cost changes, such as work activity including workovers, production levels and insurance reimbursements. Historically, costs for goods and services have moved directionally with the price of crude oil, NGLs and natural gas, as these commodities affect the demand for these goods and services. In recent years, other factors have influenced the cost of goods and services. Demand for offshore third-party contractors can be affected by hurricanes, oil spills and changes in regulations which are outside of the influences from commodity price changes. Other costs, such as insurance premiums, have fluctuated with changes in hurricane activity, the oil spills and other factors besides production volumes. Also, many commodity prices, including crude oil, copper, steel and other types of metals, have fluctuated wildly with various world events. Some of this fluctuation is due to changes in economic activity in certain parts of the world, while other changes appear to be driven by political events around the world, the changes in the value of the US dollar (both up and down) and other foreign currencies. In addition, inflation in our industry is impacted as a result of record federal deficits and expectations that large deficits will continue.

Seasonality. Generally, the demand for and price of natural gas increases during the winter months and decreases during the summer months. However, these seasonal fluctuations are somewhat reduced because during the summer, pipeline companies, utilities, local distribution companies and industrial users purchase and place into storage facilities a portion of their anticipated winter requirements of natural gas. In addition, the demand for oil is higher in the winter months, but does not fluctuate as much as natural gas. Seasonal weather changes affect our operations. Tropical storms and hurricanes occur in the Gulf of Mexico during the summer and fall, which require us to evacuate personnel and shut in production until the storm subsides. Also, periodic storms during the winter often impede our ability to safely load, unload and transport personnel and equipment, which delays the installation of production facilities, thereby delaying production and sales of our oil and natural gas.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with GAAP in the United States. The preparation of our financial statements requires us to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our estimates on historical experience and other sources that we believe to be reasonable at the time. Changes in the facts and circumstances or the discovery of new information may result in revised estimates and actual results may vary from our estimates. Our significant accounting policies are detailed in *Financial Statements and Supplementary Data – Note 1 – Significant Accounting Policies* under Part II, Item 8 in this Form 10-K. We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue recognition. We recognize oil and natural gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectability is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties with joint ownership. Under this method, we record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. If crude oil and natural gas prices decrease, we may need to increase this liability. Also, disputes may arise as to volume measurements and allocation of production components between parties. These disputes could cause us to increase our liability for such potential exposure. We do not record receivables for those properties in which the Company has taken less than its ownership share of production which could cause us to delay recognition of amounts due us.

Full-cost accounting. We account for our investments in oil and natural gas properties using the full-cost method of accounting. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and gas properties are capitalized. Capitalization of geological and geophysical costs, certain employee costs and G&A expenses related to these activities is permitted. We amortize our investment in oil and natural gas properties, capitalized ARO and future development costs (including ARO of wells to be drilled) through DD&A, using the units-of-production method. The units-of-production method uses reserve information in its calculations. The cost of unproved properties related to acquisitions are excluded from the amortization base until it is determined that proved reserves exist or until such time that impairment has occurred. We capitalize interest on unproved properties that are excluded from the amortization base. The costs of drilling non-commercial exploratory wells are included in the amortization base immediately upon determination that such wells are non-commercial. Under the full-cost method, sales of oil and natural gas properties are accounted for as adjustments to capitalized costs with no gain or loss recognized unless an adjustment would significantly alter the relationship between capitalized costs and the value of proved reserves.

Our financial position and results of operations may have been significantly different had we used the successful-efforts method of accounting for our oil and natural gas investments. GAAP allows successful-efforts accounting as an alternative method to full-cost accounting. The primary difference between the two methods is in the treatment of exploration costs, including geological and geophysical costs, and in the resulting computation of DD&A. Under the full-cost method, which we follow, exploratory costs are capitalized, while under successful-efforts, the cost associated with unsuccessful exploration activities and all geological and geophysical costs are expensed. In following the full-cost method, we calculate DD&A based on a single pool for all of our oil and natural gas properties, while the successful-efforts method utilizes cost centers represented by individual properties, fields or reserves. Typically, the application of the full-cost method of accounting for oil and natural gas properties results in higher capitalized costs and higher DD&A rates, compared to similar companies applying the successful efforts method of accounting.

DD&A can be affected by several factors other than production. The rate computation includes estimates of reserves which requires significant judgments and is subject to change at each assessment. The determination of when proved reserves exist for our unproved properties requires judgment, which can affect our DD&A rate. Also, estimates of our ARO and estimates of future development costs require significant judgment. Actual results may be significantly different from these estimates, which would affect the timing of when these expenses would be recognized in DD&A. See *Oil and natural gas reserve quantities* and *Asset retirement obligations* below for more information.

Impairment of oil and natural gas properties. Under the full cost method of accounting, we are required to periodically perform a “ceiling test,” which determines a limit on the book value of our oil and natural gas properties. Any write downs occurring as a result of the ceiling test impairment are not recoverable or reversible in future periods. We incurred significant ceiling test write-downs during 2015. We did not have any ceiling test impairments in 2014 or the previous three years. Absent a dramatic increase to commodities prices, we expect to have further ceiling test write-downs in 2016. See the *Overview* section for a discussion on the price sensitivity of the ceiling test under certain assumptions. For the effect of lower commodity prices on liquidity, see *Risk Factors - Risks Related to Financing* under Part I, Item 1A and in the *Liquidity and Capital Resources* section of this Item in this Form 10-K for additional information about our Credit Agreement and financing. For the effect of lower commodity prices on revenues and earnings, see *Quantitative and Qualitative Disclosures on Market Risks* under Part II, Item 7A in this Form 10-K for additional information.

Oil and natural gas reserve quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of DD&A and impairment assessment of our oil and natural gas properties. We make changes to DD&A rates and impairment calculations in the same period that changes to our reserve estimates are made. Our proved reserve information as of December 31, 2015 included in this Form 10-K was estimated by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, severance taxes, development costs and workovers, all of which may vary considerably from actual results;
- the accuracy of various mandated economic assumptions such as the future prices of crude oil and natural gas; and

the judgment of the persons preparing the estimates.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. See the *Overview* section for a discussion on the price sensitivity of the ceiling test under certain assumptions and the resulting sensitivity to reserve quantities.

Asset retirement obligations. We have significant obligations to plug and abandon all well bores, remove our platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells, removing pipelines, removing and disposing of offshore platforms and site cleanup. Estimating the future restoration and removal cost is difficult and requires us to make estimates and judgments because the removal obligations may be many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations, which can substantially affect our estimates of these future costs from period to period. Pursuant to GAAP, we are required to record a separate liability for the discounted present value of our ARO, with an offsetting increase to the related oil and natural gas properties on our balance sheet.

Inherent in the present value calculation of our liability are numerous estimates and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and changes in the legal, regulatory, environmental and political environments. Revisions to these estimates impact the value of our abandonment liability, our oil and natural gas property balance and our DD&A rates.

Fair value measurements. We measure the fair value of our derivative financial instruments by applying the income approach and using inputs that are derived principally from observable market data. Changes in the underlying commodity prices of the derivatives impact the unrealized and realized gain or loss recognized. We do not apply hedge accounting to our derivatives; therefore, the change in fair value for all outstanding derivatives, which include derivatives that are entered into in anticipation of future production, are reflected currently in our statements of operations. This can create timing differences between when the production is recognized and when the gain or loss on the derivative is recognized in the income statement.

Income taxes. We provide for income taxes in accordance with GAAP, which requires the use of the liability method of computing deferred income taxes, whereby deferred income taxes are recognized for the future tax consequences of the differences between the tax basis of assets and liabilities and the carrying amount in our financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Because our tax returns are filed after the financial statements are prepared, estimates are required in recording tax assets and liabilities. We record adjustments to reflect actual taxes paid in the period we complete our tax returns. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

We recognize uncertain tax positions in our financial statements when it is more likely than not that we will sustain the benefit taken or expected to be taken. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense. The final settlement of these tax positions may occur several years after the tax return is filed and may result in significant adjustments depending on the outcome of these settlements.

Share-based compensation. 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 the grant, which may be significantly different than on the date of vesting. We estimate forfeitures during the service period and make adjustments depending on actual experience. These adjustments can create timing differences on when expense is recognized.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks arising from fluctuating prices of crude oil, NGLs, natural gas and interest rates as discussed below. We have utilized derivative contracts to reduce the risk of fluctuations in commodity prices and expect to use these instruments in the future. We entered into derivative contracts for crude oil and natural gas during 2015 and had open derivative contracts as of December 31, 2015, which have staggered termination dates during 2016. We did not have any open derivative contracts as of December 31, 2014. We do not designate our commodity derivative contracts as hedging instruments. While previous derivative contracts were intended to reduce the effects of volatile oil prices, they may also have limited income from favorable price movements. For additional details about our derivative contracts, refer to *Financial Statements and Supplementary Data – Note 6 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K.

Commodity price risk. Our revenues, profitability and future rate of growth substantially depend upon market prices for crude oil, NGLs and natural gas, which fluctuate widely. Crude oil, NGLs and natural gas price declines and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. For example, assuming a 10% decline in our average realized oil, NGLs and natural gas sales prices in 2015 and assuming no other items had changed, our loss before income tax would have increased by approximately \$50 million in 2015, which excludes any estimates for ceiling-test impairment write-downs. If costs and expenses of operating our properties had increased by 10% in 2015, our loss before income tax would have increased by approximately \$21 million in 2015. These estimates exclude the potential increase to the ceiling test write-down resulting in further net losses, as a full reserve and PV-10 analysis would be required for such pro forma calculations. The amounts above would be representative of the effect on operating cash flows under the price and cost change assumptions.

Interest rate risk. As of December 31, 2015, we had no borrowings outstanding on our revolving bank credit facility and during 2015 we had amounts outstanding that ranged from zero to \$533.0 million. The revolving bank credit facility has a variable interest rate which is primarily impacted by the rates for the LIBOR and the margin ranges from 2.25% to 3.25% depending on the amount outstanding. In 2015, if interest rates would have been 100 basis points higher (an additional 1%); our interest expense would have been approximately \$3 million higher. We did not have any derivative contracts related to interest rates as of December 31, 2015.

Item 8. *Financial Statements and Supplementary Data*

W&T OFFSHORE, INC. AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	<u>Page</u>
Management's Report on Internal Control over Financial Reporting	76
Report of Independent Registered Public Accounting Firm	77
Report of Independent Registered Public Accounting Firm	78
Consolidated Financial Statements:	
Consolidated Balance Sheets as of December 31, 2015 and 2014	79
Consolidated Statements of Operations for the years ended December 31, 2015, 2014 and 2013	80
Consolidated Statements of Changes in Shareholders' Equity (Deficit) for the years ended December 31, 2015, 2014 and 2013	81
Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013	82
Notes to Consolidated Financial Statements	83

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States (GAAP). Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Accordingly, even effective internal control over financial reporting can only provide reasonable assurance of achieving their control objectives.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework).

Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2015 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of W&T Offshore, Inc. and Subsidiaries

We have audited W&T Offshore, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). W&T Offshore, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, W&T Offshore, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in shareholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2015 and our report dated March 9, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 9, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of W&T Offshore, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in shareholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of W&T Offshore, Inc. and subsidiaries at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), W&T Offshore, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 9, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 9, 2016

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

	December 31,	
	2015	2014
Assets		
Current assets:		
Cash and cash equivalents	\$ 85,414	\$ 23,666
Receivables:		
Oil and natural gas sales	35,005	67,242
Joint interest and other	22,012	43,645
Total receivables	57,017	110,887
Prepaid expenses and other assets	26,879	36,347
Total current assets	169,310	170,900
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which \$18,595 at December 31, 2015 and \$109,824 at December 31, 2014 were excluded from amortization)	7,902,494	8,045,666
Furniture, fixtures and other	20,802	23,269
Total property and equipment	7,923,296	8,068,935
Less accumulated depreciation, depletion and amortization	6,933,247	5,575,078
Net property and equipment	990,049	2,493,857
Deferred income taxes	27,595	—
Restricted deposits for asset retirement obligations	15,606	15,444
Other assets	5,462	9,307
Total assets	<u>\$ 1,208,022</u>	<u>\$ 2,689,508</u>
Liabilities and Shareholders' Equity (Deficit)		
Current liabilities:		
Accounts payable	\$ 109,797	\$ 194,109
Undistributed oil and natural gas proceeds	21,439	37,009
Asset retirement obligations	84,335	36,003
Accrued liabilities	11,922	17,377
Total current liabilities	227,493	284,498
Long-term debt	1,196,855	1,352,120
Asset retirement obligations, less current portion	293,987	354,565
Deferred income taxes	—	175,326
Other liabilities	16,178	13,691
Commitments and contingencies	—	—
Shareholders' equity (deficit):		
Preferred stock, \$0.00001 par value; 20,000,000 shares authorized; 0 issued at December 31, 2015 and 2014	—	—
Common stock, \$0.00001 par value; 118,330,000 shares authorized; 79,375,662 issued and 76,506,489 outstanding at December 31, 2015; 78,768,588 issued and 75,899,415 outstanding at December 31, 2014	1	1
Additional paid-in capital	423,499	414,580
Retained earnings (deficit)	(925,824)	118,894
Treasury stock, at cost; 2,869,173 shares at December 31, 2015 and 2014	(24,167)	(24,167)
Total shareholders' equity (deficit)	(526,491)	509,308
Total liabilities and shareholders' equity (deficit)	<u>\$ 1,208,022</u>	<u>\$ 2,689,508</u>

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands except per share data)

	Year Ended December 31,		
	2015	2014	2013
Revenues	\$ 507,265	\$ 948,708	\$ 984,088
Operating costs and expenses:			
Lease operating expenses	192,765	264,751	270,839
Production taxes	3,002	7,932	7,135
Gathering and transportation	17,157	19,821	17,510
Depreciation, depletion and amortization	373,368	490,469	430,611
Asset retirement obligations accretion	20,703	20,633	20,918
Ceiling test write-down of oil and natural gas properties	987,238	—	—
General and administrative expenses	73,110	86,999	81,874
Derivative (gain) loss	(14,375)	(3,965)	8,470
Total costs and expenses	<u>1,652,968</u>	<u>886,640</u>	<u>837,357</u>
Operating income (loss)	(1,145,703)	62,068	146,731
Interest expense:			
Incurred	104,592	86,922	85,639
Capitalized	(7,256)	(8,526)	(10,058)
Other (income) expense, net	4,663	(208)	(8,946)
Income (loss) before income tax expense (benefit)	(1,247,702)	(16,120)	80,096
Income tax expense (benefit)	(202,984)	(4,459)	28,774
Net income (loss)	<u>\$ (1,044,718)</u>	<u>\$ (11,661)</u>	<u>\$ 51,322</u>
Basic and diluted earnings (loss) per common share	\$ (13.76)	\$ (0.16)	\$ 0.68

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (DEFICIT)
(In thousands)

	Common Stock Outstanding		Additional Paid-In Capital	Retained Earnings (Deficit)	Treasury Stock		Total Shareholders' Equity (Deficit)
	Shares	Value			Shares	Value	
Balances at December 31, 2012	75,250	\$ 1	\$ 396,186	\$ 169,167	2,869	\$ (24,167)	\$ 541,187
Cash dividends:							
Common stock regular (\$0.36 per share)	—	—	—	(27,098)	—	—	(27,098)
Common stock special (\$0.42 per share)	—	—	—	(31,748)	—	—	(31,748)
Share-based compensation	—	—	11,525	—	—	—	11,525
Stock issued	342	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(2,370)	—	—	—	(2,370)
Other	—	—	(1,777)	(431)	—	—	(2,208)
Net income	—	—	—	51,322	—	—	51,322
Balances at December 31, 2013	75,592	1	403,564	161,212	2,869	(24,167)	540,610
Cash dividends:							
Common stock regular (\$0.40 per share)	—	—	—	(30,260)	—	—	(30,260)
Share-based compensation	—	—	14,744	—	—	—	14,744
Stock issued	307	—	—	—	—	—	—
RSUs and shares surrendered for payroll taxes	—	—	(848)	—	—	—	(848)
Other	—	—	(2,880)	(397)	—	—	(3,277)
Net loss	—	—	—	(11,661)	—	—	(11,661)
Balances at December 31, 2014	75,899	1	414,580	118,894	2,869	(24,167)	509,308
Share-based compensation	—	—	10,242	—	—	—	10,242
Stock issued	607	—	—	—	—	—	—
RSUs and shares surrendered for payroll taxes	—	—	(674)	—	—	—	(674)
Other	—	—	(649)	—	—	—	(649)
Net loss	—	—	—	(1,044,718)	—	—	(1,044,718)
Balances at December 31, 2015	<u>76,506</u>	<u>\$ 1</u>	<u>\$ 423,499</u>	<u>\$ (925,824)</u>	<u>2,869</u>	<u>\$ (24,167)</u>	<u>\$ (526,491)</u>

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2015	2014	2013
Operating activities:			
Net income (loss)	\$ (1,044,718)	\$ (11,661)	\$ 51,322
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	394,071	511,102	451,529
Ceiling test write-down of oil and gas properties	987,238	—	—
Debt issuance costs write-down/amortization of debt items	4,411	701	1,645
Share-based compensation	10,242	14,744	11,525
Derivative (gain) loss	(14,375)	(3,965)	8,470
Cash receipts (payments) on derivative settlements, net	6,703	(5,318)	(8,589)
Deferred income taxes	(203,272)	(4,760)	30,920
Changes in operating assets and liabilities:			
Oil and natural gas receivables	32,236	29,510	980
Joint interest and other receivables	21,633	(4,255)	34,257
Income taxes	(7)	3,143	44,328
Prepaid expenses and other assets	17,816	15,012	(10,044)
Asset retirement obligation settlements	(32,555)	(74,313)	(81,543)
Accounts payable, accrued liabilities and other	(46,869)	4,033	27,908
Net cash provided by operating activities	<u>132,554</u>	<u>473,973</u>	<u>562,708</u>
Investing activities:			
Acquisition of property interest in oil and natural gas properties	—	(72,234)	(82,424)
Investment in oil and natural gas properties and equipment	(230,161)	(554,378)	(551,954)
Changes in operating assets and liabilities associated with investing activities	(55,425)	37,450	(1,350)
Net proceeds from sales of assets	372,939	—	21,008
Purchases of furniture, fixtures and other	(1,278)	(3,340)	(1,435)
Net cash provided by (used in) investing activities	<u>86,075</u>	<u>(592,502)</u>	<u>(616,155)</u>
Financing activities:			
Borrowings of long-term debt - revolving bank credit facility	263,000	556,000	563,000
Repayments of long-term debt - revolving bank credit facility	(710,000)	(399,000)	(443,000)
Issuance of 9.00% Term Loan	297,000	—	—
Debt issuance costs	(6,669)	—	(3,892)
Dividends to shareholders	—	(30,260)	(58,846)
Other	(212)	(345)	(260)
Net cash provided by (used in) financing activities	<u>(156,881)</u>	<u>126,395</u>	<u>57,002</u>
Increase in cash and cash equivalents	61,748	7,866	3,555
Cash and cash equivalents, beginning of period	23,666	15,800	12,245
Cash and cash equivalents, end of period	<u>\$ 85,414</u>	<u>\$ 23,666</u>	<u>\$ 15,800</u>

See accompanying notes

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

Operations

W&T Offshore, Inc. and subsidiaries, referred to herein as “W&T,” “we,” “us,” “our,” or the “Company”, is an independent oil and natural gas producer focused primarily in the Gulf of Mexico. On October 15, 2015, a substantial amount of our interest in onshore acreage was sold, which is described in Note 2. The Company is active in the exploration, development and acquisition of oil and natural gas properties. Our interest in fields, leases, structures and equipment are primarily owned by the parent company, W&T Offshore, Inc. (on a stand-alone basis, the “Parent Company”) and our wholly-owned subsidiary, W & T Energy VI, LLC (“Energy VI”).

Basis of Presentation

Our consolidated financial statements include the accounts of W&T Offshore, Inc. and its majority-owned subsidiaries. All significant intercompany transactions and amounts have been eliminated for all years presented. Our consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (“GAAP”) and the appropriate rules and regulations of the Securities and Exchange Commission (“SEC”).

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, the reported amounts of revenues and expenses during the reporting periods and the reported amounts of proved oil and natural gas reserves. Actual results could differ from those estimates.

Early Adoption of Accounting Standard Amendments

Accounting Standards Update No. 2015-03 (“ASU 2015-03”), *Interest – Imputation of Interest (Subtopic 835-30), Simplifying the Presentation of Debt Issuance Costs*, was early adopted as of December 31, 2015 and applied on a retrospective basis. The amendment requires debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of liability, consistent with debt discounts or premiums. The guidance also clarified that debt issuance costs related to credit facilities could be reported as an asset regardless of the balance outstanding. The adoption of ASU 2015-03 resulted in \$7.9 million of unamortized debt issuance costs reclassified from long-term assets to a reduction in long-term liabilities as of December 31, 2014. We elected to continue to report unamortized debt issuance costs related to our revolving bank credit facility as a long-term asset. The early adoption of ASU 2015-03 did not affect the statements of operations or the statements of cash flows. See Note 7 for additional information.

Accounting Standards Update No. 2015-17 (“ASU 2015-17”), *Balance Sheet Classification of Deferred Taxes*, was early adopted as of December 31, 2015 and applied on a retrospective basis. The amendment requires all deferred tax assets and liabilities to be classified as noncurrent. For the Balance Sheet as of December 31, 2014, \$11.7 million of deferred tax assets was reclassified from *Current assets* to *Deferred income taxes liability* (noncurrent). The early adoption of ASU 2015-17 did not affect the statements of operations or the statements of cash flows. See Note 13 for additional information.

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

Reclassifications

Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation as follows: Within the Consolidated Statements of Cash Flows, adjustments were made for the changes in operating assets and liabilities associated with investing activities. The adjustments resulted in Net cash provided by operating activities and Net cash used in investing activities to be decreased by \$37.5 million for 2014 and increased by \$1.4 million for 2013. Similar adjustments were made in the Condensed Consolidating Statements of Cash flow totaling the same amounts for the respective years. The adjustments did not affect the Consolidated Balance Sheets or the Consolidated Statements of Operations.

Transactions between Entities under Common Control

The prior period financial information for 2014 presented in Note 20, *Supplemental Guarantor Information*, has been retrospectively adjusted due to transactions between entities under common control, as required under authoritative guidance.

Recent Events

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

We have taken several steps during 2015 to mitigate the effects of these lower prices including: (i) significantly reducing 2015 capital spending from the previous year and budgeted further reductions in capital spending for 2016 (exclusive of acquisitions); (ii) suspending our drilling and completion activities at several locations; (iii) suspending the regular quarterly common stock dividend; (iv) implementing numerous cost reduction projects to reduce our operating costs; (v) entered into a second lien term loan (the "9.00% Term Loan"); (vi) entered into three Amendments to our Fifth Amended and Restated Credit Agreement (as amended, the "Credit Agreement"); and (vii) sold our interest in the Yellow Rose onshore field. See Notes 2 and Note 7 for additional information.

In February 2016, we announced that we had borrowed \$340.0 million under the Credit Agreement for general corporate purposes. Also, in February and March 2016, we received demands from the Bureau of Ocean Energy Management ("BOEM") ordering us to secure financial assurances totaling approximately \$260.8 million, with amounts specified by certain designated leases. See Note 20 for additional information.

We have assessed our financial condition, the current capital markets and options given different scenarios of commodity prices and believe we will have adequate liquidity to fund our operations through December 31, 2016; however, we cannot predict how an extended period of low commodity prices or the impact of future bonding requirements will affect our operations and liquidity levels.

Cash Equivalents

We consider all highly liquid investments purchased with original or remaining maturities of three months or less at the date of purchase to be cash equivalents.

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

Revenue Recognition

We recognize oil and natural gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectability is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties with joint ownership. Under this method, we record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which the Company has taken less than its ownership share of production. At December 31, 2015 and 2014, \$6.9 million and \$6.4 million, respectively, were included in current liabilities related to natural gas imbalances.

Concentration of Credit Risk

Our customers are primarily large integrated oil and natural gas companies and large financial institutions. Our production is sold utilizing month-to-month contracts that are based on bid prices. We also have receivables from joint interest owners on properties we operate and we may have the ability to withhold future revenue disbursements to recover amounts due us. We attempt to minimize our credit risk exposure to purchasers of our oil and natural gas, joint interest owners, derivative counterparties and other third-party entities through formal credit policies, monitoring procedures, and letters of credit or guaranties when considered necessary. We historically have not had any significant problems collecting our receivables, but with the decline in commodity prices, several oil and gas companies have filed for bankruptcy. We use the specific identification method of determining if an allowance for doubtful accounts is needed. As of December 31, 2015 and 2014, we recorded \$2.5 million and \$0.7 million, respectively, in the allowance for doubtful accounts. During 2015 and 2014, there was no usage of the amounts recorded for allowance for doubtful accounts.

The following identifies customers from whom we derived 10% or more of receipts from sales of crude oil, NGLs and natural gas.

Customer	Year Ended December 31,		
	2015	2014	2013
Shell Trading (US) Co.	50 %	47 %	48 %
J. P. Morgan	14 %	**	**

** less than 10%

We believe that the loss of any of the customers above would not result in a material adverse effect on our ability to market future oil and natural gas production as replacement customers could be obtained in a relatively short period of time on terms, conditions and pricing substantially similar to those currently existing.

Insurance Receivables

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. See Note 18 for information related to unpaid claims by certain underwriters.

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

Prepaid expenses and other

Amounts recorded in *Prepaid expenses and other* on the Consolidated Balance Sheets are expected to be realized within one year. Items representing 5% or more of total current assets in either period presented are disclosed in the following table:

	Year Ended December 31,	
	2015	2014
Derivative assets - current (1)	\$ 10,036	\$ 7,417
Prepaid insurance and surety bonds	7,475	13,130
Prepaid deposits related to royalties	5,943	9,681
Other (2)	3,425	6,119
Prepaid expenses and other	\$ 26,879	\$ 36,347

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

(2) Individual items were less than 5% of total current assets for either period presented.

Properties and Equipment

We use the full-cost method of accounting for oil and natural gas properties and equipment. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and natural gas properties are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire properties. Exploration costs include costs of drilling exploratory wells and external geological and geophysical costs, which mainly consist of seismic costs. Development costs include the cost of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production, certain geological and geophysical costs and general and administrative costs are expensed in the period incurred.

Oil and natural gas properties and equipment include costs of unproved properties. The cost of unproved properties related to significant acquisitions are excluded from the amortization base until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. The costs of drilling exploratory dry holes are included in the amortization base immediately upon determination that such wells are non-commercial.

We capitalize interest on the amount of unproved properties that are excluded from the amortization base. Interest is capitalized only for the period that exploration and development activities are in progress. Capitalization of interest ceases when the property is moved into the amortization base. All capitalized interest is recorded within *Oil and natural gas property and equipment* on the Consolidated Balance Sheets.

Oil and natural gas properties included in the amortization base are amortized using the units-of-production method based on production and estimates of proved reserve quantities. In addition to costs associated with evaluated properties and capitalized asset retirement obligations ("ARO"), the amortization base includes estimated future development costs to be incurred in developing proved reserves as well as estimated plugging and abandonment costs, net of salvage value, related to developing proved reserves. Future development costs related to proved reserves are not recorded as liabilities on the balance sheet, but are part of the calculation of depletion expense.

Sales of proved and unproved oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

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

Furniture, fixtures and non-oil and natural gas property and equipment are depreciated using the straight-line method based on the estimated useful lives of the respective assets, generally ranging from five to seven years. Leasehold improvements are amortized over the shorter of their economic lives or the lease term. Repairs and maintenance costs are expensed in the period incurred.

Ceiling Test Write-Down

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

Due primarily to declines in the unweighted rolling 12-month average of first-day-of-the-month commodity prices for oil and natural gas, we recorded ceiling test write-downs in 2015 which are reported as a separate line in the Statements of Operations. The average price using the SEC required methodology at December 31, 2015 was \$46.79 per barrel for West Texas Intermediate ("WTI") crude oil and \$2.59 per million British Thermal Unit ("MMBtu") for Henry Hub natural gas. These prices are before adjustments for quality, transportation, fees, energy content and regional price differentials. The ceiling test write-downs of the carrying value of our oil and natural gas properties, which included \$32.4 million in the fourth quarter of 2015, were \$987.2 million for the full year of 2015. We did not record a ceiling test write-down during 2014 or 2013. If crude oil and natural gas prices remain or decrease from current levels, it is probable that a ceiling test write-down will be recorded in the first quarter of 2016 and possibly in subsequent quarters during 2016.

Asset Retirement Obligations

We are required to record a separate liability for the present value of our ARO, with an offsetting increase to the related oil and natural gas properties on our balance sheet. We have significant obligations to plug and abandon well bores, remove our platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells, removing pipelines, removing and disposing of offshore platforms and site cleanup. Estimating the future restoration and removal cost is difficult and requires us to make estimates and judgments because the removal obligations may be many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations, which can substantially affect our estimates of these future costs from period to period. For additional information, refer to Note 5.

Oil and Natural Gas Reserve Information

We use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period when estimating quantities of proved reserves. Similarly, the prices used to calculate the standardized measure of discounted future cash flows and prices used in the ceiling test for impairment are the 12-month average commodity prices. Proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years, with some limited exceptions allowed. Refer to Note 21 for additional information about our proved reserves.

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

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 credit facility. Our derivative instruments currently consist of commodity swap contracts for oil. We do not enter into derivative instruments for speculative trading purposes.

Derivative instruments are recorded on the balance sheet as an asset or a liability at fair value. Changes in a derivative's fair value are required to be recognized currently in earnings unless specific hedge accounting and documentation criteria are met at the time the derivative contract is entered into. We have elected not to designate our commodity derivatives as hedging instruments, therefore, all changes in fair value are recognized in earnings.

Fair Value of Financial Instruments

We include fair value information in the notes to our consolidated financial statements when the fair value of our financial instruments is different from the book value or it is required by applicable guidance. We believe that the book value of our cash and cash equivalents, receivables, accounts payable and accrued liabilities materially approximates fair value due to the short-term nature and the terms of these instruments. We believe that the book value of our restricted deposits approximates fair value as deposits are in cash or short-term investments. We believe 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.

Fair Value of Acquisitions

Acquisitions are recorded on the closing date of the transaction at their fair value, which is determined by applying the market and income approaches using Level 3 inputs. The Level 3 inputs are: (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 are 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 can vary significantly from estimates that are made. No goodwill was recorded for the acquisitions completed in 2014 or 2013.

Income Taxes

We use the liability method of accounting for income taxes in accordance with the *Income Taxes* topic of the Codification. Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. We recognize uncertain tax positions in our financial statements when it is more likely than not that we will sustain the benefit taken or expected to be taken. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense. See *Early Adoption of Accounting Standard Amendments* above and Note 13 for additional information.

Debt Issuance Costs

Debt issuance costs associated with our revolving bank credit facility are amortized using the straight-line method over the scheduled maturity of the debt. Debt issuance costs associated with all other debt are deferred and amortized over the scheduled maturity of the debt utilizing the effective interest method. As described above, unamortized debt issuance costs associated with our revolving bank credit facility is reported within *Other Assets* (noncurrent) and unamortized debt issuance costs associated with our other debt is reported as a reduction in *Long-Term Debt, less current maturities* in the Consolidated Balance Sheets. See Note 7 for additional information.

Premiums Received and Discounts Provided on Debt Issuance

Premiums and discounts are recorded in *Long-Term Debt, less current maturities* in the Consolidated Balance Sheets and are amortized over the term of the related debt using the effective interest method.

Share-Based Compensation

Compensation cost for share-based payments to employees and non-employee directors is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which the recipient is required to provide service in exchange for the award. The fair value for equity instruments subject to only time or to Company performance measures was determined using the closing price of the Company's common stock at the date of grant. The fair value of equity instruments subject to market-based performance measurements was determined using a Monte Carlo simulation probabilistic model. We recognize share-based compensation expense on a straight line basis over the period during which the recipient is required to provide service in exchange for the award. Estimates are made for forfeitures during the vesting period, resulting in the recognition of compensation cost only for those awards that are estimated to vest and estimated forfeitures are adjusted to actual forfeitures when the equity instrument vests. See Note 11 for more information.

Earnings Per Share

Unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per share under the two-class method. For additional information, refer to Note 14.

Other (Income) Expense, Net

For 2015, the amount includes write-offs of debt issuance costs of \$3.2 million related to reductions in the borrowing base of the revolving bank credit facility under the Credit Agreement. The write-offs of debt issuance costs is included as an adjustment to net income in determining *Net cash provided by operating activities* in the Consolidated Statements of Cash Flows as the write-offs were non-cash transactions. For 2013, the amount reported consisted primarily of \$9.1 million of net proceeds received in conjunction with a payment for an option exercised by a counterparty. The net amount was included in *Net cash flows from investing activities* within the line, *Net proceeds from sales of assets* in the Consolidated Statements of Cash Flows.

Recent Accounting Developments

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

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

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

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

2. Acquisitions and Divestitures

2015 Divestiture

On October 15, 2015, we sold certain onshore oil and natural gas property interests to Ajax Resources, LLC (“Ajax”) for approximately \$372.9 million in cash, which includes certain customary price adjustments, and Ajax assumed responsibility for the related ARO. The effective date of the sale was January 1, 2015. Ajax acquired all of our interest in the Yellow Rose field in the Permian Basin, covering approximately 25,800 net acres in Andrews, Martin, Gaines and Dawson counties in West Texas. We retained a non-expense bearing overriding royalty interest (“ORRI”) in production from the working interests assigned to Ajax, which percentage varies on a sliding scale from one percent for each month that the prompt month New York Mercantile Exchange (“NYMEX”) trading price for light sweet crude oil is at or below \$70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than \$90.00 per barrel. We used a portion of the proceeds of the sale to repay all outstanding borrowings under the revolving bank credit facility, while the remaining balance of approximately \$100.0 million was added to available cash.

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

2014 Acquisitions

Fairway

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

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

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

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

The acquisition was recorded at fair value, which was determined using both the market and income approaches, and Level 3 inputs were used to determine fair value. See Note 1 for a description of the Level 3 inputs. No goodwill was recorded in connection with the acquisition of this additional working interest in Fairway.

Woodside Properties

On May 20, 2014, Energy VI entered into a purchase and sale agreement to acquire certain oil and natural gas property interests from Woodside Energy (USA) Inc. (“Woodside”). The properties acquired from Woodside (the “Woodside Properties”) consisted of a 20% non-operated working interest in the producing Neptune field (deepwater Atwater Valley blocks 574, 575 and 618), along with an interest in the Neptune tension-leg platform, associated production facilities and various interests in 24 other deepwater lease blocks. All of the Woodside Properties are located in the Gulf of Mexico. The effective date of the transaction was November 1, 2013. The transaction included customary adjustments for the effective date, certain closing adjustments and our assumption of the related ARO. A net purchase price increase of \$0.2 million for customary final closing adjustments was recorded in 2015. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

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

Cash consideration:	
Evaluated properties including equipment	\$ 52,347
Unevaluated properties	2,660
Sub-total cash consideration	55,007
Non-cash consideration:	
Asset retirement obligations - current	782
Asset retirement obligations - non-current	10,543
Sub-total non-cash consideration	11,325
Total consideration	\$ 66,332

The acquisition was recorded at fair value, which was determined using both the market and income approaches, and Level 3 inputs were used to determine fair value. See Note 1 for a description of the Level 3 inputs. No goodwill was recorded in connection with the Woodside Properties acquisition.

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

The increase in working interest ownership for Fairway was not included in our consolidated results until the property transfer date, which occurred in September 2014 and the incremental revenue and operating expenses were immaterial for 2014. Unaudited pro forma information is not presented as the pro forma information is not materially different from the reported results for 2014 and 2013.

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

The Woodside Properties were not included in our consolidated results until the property transfer date, which occurred on May 20 2014. For 2015, the Woodside Properties accounted for \$24.4 million of revenues, \$9.5 million of direct operating expenses, \$14.4 million of depreciation, depletion, amortization and accretion (“DD&A”) and no income tax expense, resulting in \$0.5 million of net income. For the period of May 20, 2014 to December 31, 2014, the Woodside Properties accounted for \$28.4 million of revenues, \$5.5 million of direct operating expenses, \$11.0 million of DD&A and \$4.2 million of income taxes, resulting in \$7.7 million of net income. The net income attributable to the Woodside Properties does not reflect certain expenses, such as general and administrative expenses (“G&A”) and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Woodside Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate.

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

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

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

	(unaudited)	
	Year Ended December 31,	
	2014	2013
Revenue	\$ 971,595	\$ 1,047,037
Net income	(5,503)	71,412
Basic and diluted earnings per common share	(0.08)	0.94

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

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

	(unaudited)	
	Year Ended December 31,	
	2014 (a)	2013
Revenues (b)	\$ 22,887	\$ 62,949
Direct operating expenses (b)	4,417	9,583
DD&A (c)	8,385	20,503
G&A (d)	300	800
Interest expense (e)	330	990
Capitalized interest (f)	(19)	165
Income tax expense (g)	3,316	10,818

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

The sources of information and significant assumptions are described below:

- (a) The adjustments for 2014 are for the period from January 1, 2014 to May 20, 2014.
- (b) Revenues and direct operating expenses for the Woodside Properties were derived from the historical financial records of Woodside.
- (c) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Woodside Properties' costs, reserves and production into our full cost pool in order to compute such amounts. The purchase price allocated to unevaluated properties for oil and natural gas interests was excluded from the DD&A expense estimation. ARO was estimated by W&T management.
- (d) Estimated insurance costs related to the Woodside Properties.
- (e) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of \$55.0 million, which equates to the cash component of the acquisition purchase price, and an interest rate of 1.8%, which equates to the rates applied to incremental borrowings on the revolving bank credit facility.
- (f) The change to capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings. The negative amount represents a decrease to net expenses.
- (g) Income tax expense was computed using the 35% federal statutory rate.

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

2013 Acquisition

On October 17, 2013, W&T Offshore, Inc. entered into a purchase and sale agreement to acquire certain oil and natural gas property interests from Callon Petroleum Operating Company ("Callon"). Pursuant to the purchase and sale agreement, transfers of certain properties that had no preferential rights were consummated on November 5, 2013 and transfers of certain properties subject to preferential rights, of which third-parties declined to exercise their preferential rights, were consummated on December 4, 2013. The properties acquired from Callon (the "Callon Properties") consist of a 15% working interest in the Medusa field (deepwater Mississippi Canyon blocks 538 and 582), interest in associated production facilities and various interests in other non-operated fields. All of the Callon Properties are located in the Gulf of Mexico. The effective date of the transaction was July 1, 2013. The transaction included customary adjustments for the effective date, certain closing adjustments and we assumed the related ARO. An upward net purchase price adjustment of \$0.6 million was recorded during 2014. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

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

Cash consideration:	
Evaluated properties including equipment	\$ 73,752
Unevaluated properties	9,248
Sub-total cash consideration	83,000
Non-cash consideration:	
Asset retirement obligations - current	90
Asset retirement obligations - non-current	4,143
Sub-total non-cash consideration	4,233
Total consideration	\$ 87,233

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

The acquisition was recorded at fair value, which was determined using both the market and income approaches, and Level 3 inputs were used to determine fair value. See Note 1 for a description of the Level 3 inputs. No goodwill was recorded in connection with the acquisition of the Callon Properties.

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

The Callon Properties were not included in our consolidated results until the respective property transfer dates, which occurred during the fourth quarter of 2013. In 2014, the Callon Properties accounted for \$32.5 million of revenue, \$6.6 million of direct operating expenses, \$16.4 million of DD&A and \$3.3 million of income taxes, resulting in \$6.2 million of net income. In the fourth quarter of 2013, the Callon Properties accounted for \$5.8 million of revenues, \$1.3 million of direct operating expenses, \$2.4 million of DD&A and \$0.7 million of income taxes, resulting in \$1.4 million of net income. The net income attributable to these properties does not reflect certain expenses, such as G&A and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Callon Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate.

The unaudited pro forma financial information presented below was computed as if the acquisition of the Callon Properties had been completed on January 1, 2012. The financial information was derived from W&T's audited historical consolidated financial statements, the Callon Properties' audited historical financial statement, and the Callon Properties' unaudited historical financial statement for the periods presented.

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

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

	(unaudited)
	Year Ended
	December 31, 2013
Revenue	\$ 1,018,118
Net income	59,015
Basic and diluted earnings per common share	0.78

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

For the pro forma financial information, certain information was derived from financial records and certain information was estimated. The following table presents incremental items included in the pro forma information reported above for the Callon Properties (in thousands):

		(unaudited) Year Ended December 31, 2013 (a)
Revenues (b)	\$	34,030
Direct operating expenses (b)		6,405
DD&A (c)		14,931
G&A (d)		(361)
Interest expense (e)		1,383
Capitalized interest (f)		(164)
Income tax expense (g)		4,143

The sources of information and significant assumptions are described below:

- (a) The adjustments for 2013 are for the period from January 1, 2013 to the respective property transfer date, all of which occurred in the fourth quarter of 2013.
- (b) Revenues and direct operating expenses for the Callon Properties were derived from the historical financial records of Callon.
- (c) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Callon Properties' costs, reserves and production into our currently existing full cost pool in order to compute such amounts. The purchase price allocated to unevaluated properties for oil and natural gas interests was excluded from the DD&A expense estimation. ARO was estimated by W&T management.
- (d) G&A adjustments related to incremental transaction expenses, which were assumed to be funded from cash on hand, and were adjusted from the 2013 results.
- (e) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of \$83.0 million, which equates to the cash component of the transaction, and an interest rate of 2.0%, which equates to the rates applied to incremental borrowings on the revolving bank credit facility.
- (f) The change to capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings. A positive amount represents an increase to net expenses and a negative amount represents a decrease to net expenses.
- (g) Income tax expense was computed using the 35% federal statutory rate.

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

2013 Divestitures

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

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

On September 26, 2013, we sold our working interests in the West Delta area block 29 with an effective date of January 1, 2013. The property is located in the Gulf of Mexico. Including adjustments for the effective date, the net proceeds were \$14.7 million, which includes a \$1.7 million post-effective-date repayment that occurred during 2014. The transaction was structured as a like-kind exchange under the Internal Revenue Service Code ("IRC") Section 1031 and other applicable regulations, with funds held by a qualified intermediary until replacement purchases are made. Replacement purchases were made in 2013, which were within the replacement periods as defined under the IRC. In connection with this sale, we reversed \$3.9 million of ARO.

3. Hurricane Remediation and Insurance Claims

During the third quarter of 2008, Hurricane Ike caused substantial damage to certain of our properties. 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.

For 2015, 2014 and 2013, we have received insurance proceeds of \$0.2 million, \$12.2 million and \$6.7 million, respectively, primarily related to hurricane damage. These amounts are included within *Net cash provided by operating activities* in the Consolidated Statement of Cash Flows and are primarily recorded as reductions in *Oil and natural gas properties and equipment* on the Consolidated Balance Sheets, with minor amounts recorded as reductions in *Lease operating expense* in the Consolidated Statements of Operations. From the third quarter of 2008 through December 31, 2014, we have received \$161.2 million cumulative from our insurance underwriters related to Hurricane Ike. See Note 18 for information regarding legal actions involving certain insurers and the Company concerning claims related to Hurricane Ike damages.

4. Restricted Deposits

Restricted deposits as of December 31, 2015 and 2014 consisted of funds escrowed for the future plugging and abandonment of certain oil and natural gas properties.

Pursuant to the Purchase and Sale Agreement with Total E&P USA Inc. ("Total E&P"), security for future plugging and abandonment of certain oil and natural gas properties is required either through surety bonds or payments to an escrow account or a combination thereof. Monthly payments are made to an escrow account and these funds are returned to us once verification is made that the security amount requirements have been met. We were in compliance with the security requirements as of December 31, 2015. See Note 16 for potential future security requirements.

5. Asset Retirement Obligations

Asset retirement obligations associated with the retirement of tangible long-lived assets are required to be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset. The fair value of the ARO is measured using expected cash outflows associated with the ARO, discounted at our credit-adjusted risk-free rate when the liability is initially recorded. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

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

The following is a reconciliation of our ARO liability (in thousands):

	Year Ended December 31,	
	2015	2014
Asset retirement obligations, beginning of period	\$ 390,568	\$ 354,422
Liabilities settled	(32,555)	(74,313)
Accretion of discount	20,703	20,633
Disposition of properties	(8,581)	—
Liabilities assumed through acquisition	2,944	21,820
Liabilities incurred	4,780	3,258
Revisions of estimated liabilities	463	64,748
Asset retirement obligations, end of period	378,322	390,568
Less current portion	84,335	36,003
Long-term	<u>\$ 293,987</u>	<u>\$ 354,565</u>

During 2015, we decreased our ARO on an overall basis primarily due to plug and abandonment work performed during 2015, partially offset by increases from accretion. Revisions were basically flat as some service providers reduced their costs of goods and services, some service provider costs remained flat and some service provider costs estimates were increased, all of which were incorporated into our estimates. In addition, revisions were made for scope changes and on the estimates of timing of when the work will be performed. Liability increases from acquisitions and wells drilled were basically offset by reductions from dispositions.

During 2014, we increased our ARO on an overall basis primarily due to revisions, acquisitions and accretion of discount. Revisions increased ARO on a net basis primarily attributable to: a) increases at certain non-operated properties, b) regulation interpretations issued by the Bureau of Safety and Environmental Enforcement (“BSEE”), which increased the amount of work involved, c) revisions to third-party contractor estimated prices for certain work on wells and structures, d) revisions accelerating the timing of planned work for certain wells and e) revisions for certain wells that are taking longer to complete the plugging and abandonment work than previously estimated due to operational issues. Increases related to acquisitions include the increase in our ownership interest at Fairway, the acquisition of the Woodside Properties and other minor acquisitions. Partially offsetting these were decreases for the plug and abandonment work performed during the year and the disposition of certain properties.

6. Derivative Financial Instruments

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

Each derivative contract is recorded on the balance sheet as an asset or liability at fair value as of the respective period. We have elected not to designate our commodity derivative contracts as hedging instruments; therefore, all changes in the fair value of derivative contracts were recognized currently in earnings during the periods presented. The cash flows of all of our commodity derivative contracts are included in *Net cash provided by operating activities* on the Condensed Consolidated Statements of Cash Flows.

For information about fair value measurements, refer to Note 8.

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

Commodity Derivatives

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

As of December 31, 2014, we did not have any open derivative contracts. During 2014 and 2013, we used crude oil swap contracts and have used various derivative instruments in prior years to manage our exposure to commodity price risk from sales of our oil and natural gas. While these contracts were intended to reduce the effects of price volatility, they may have limited incremental income from favorable price movements.

As of December 31, 2015, our open commodity derivative contracts were as follows:

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

Termination Period		Notional Quantity (Bbls/day) (1)	Notional Quantity (Bbls) (1)	Weighted Average Contract Price	
				Put Option (Bought)	Call Option (Sold)
2016:	1st Quarter	5,000	455,000	\$ 40.00	\$ 81.47
	2nd Quarter	5,000	455,000	40.00	81.47
	3rd Quarter	5,000	460,000	40.00	81.47
	4th Quarter	5,000	460,000	40.00	81.47
			1,830,000	40.00	81.47

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

Termination Period		Notional Quantity (MMBTUs/day) (1)	Notional Quantity (MMBTUs) (1)	Weighted Average Contract Price		
				Put Option (Bought)	Call Option (Sold)	Call Option (Bought)
2016:	1st Quarter (2)	40,000	2,400,000	\$ 2.25	\$ 3.50	\$ 3.77
	2nd Quarter	40,000	3,640,000	2.25	3.50	3.77
	3rd Quarter	40,000	3,680,000	2.25	3.50	3.77
	4th Quarter	40,000	3,680,000	2.25	3.50	3.77
			13,400,000	2.25	3.50	3.77

(1) Volume Measurements: Bbls – barrels; MMBTUs – million British Thermal Units.

(2) The natural gas derivative contracts are priced and closed in the last week prior to the related production month. Natural gas derivative contracts related to January 2016 production were priced and closed in December 2015 and are excluded in the above table as these were closed contracts as of December 31, 2015.

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

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

	December 31,	
	2015	2014
Prepaid and other assets - current	\$ 7,672	\$ —

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

	Year Ended December 31,		
	2015	2014	2013
Derivative (gain) loss:	\$ (14,375)	\$ (3,965)	\$ 8,470

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

	Year Ended December 31,		
	2015	2014	2013
Cash receipts (payments) on derivative settlements, net	\$ 6,703	\$ (5,318)	\$ (8,589)

Offsetting Commodity Derivatives

During 2015, all our commodity derivative contracts permit netting of derivative gains and losses upon settlement. In general, the terms of the contracts provide for offsetting of amounts payable or receivable between us and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same commodity. If an event of default were to occur causing an acceleration of payment under our revolving bank credit facility, that event may also trigger an acceleration of settlement of our derivative instruments. If we were required to settle all of our open derivative contracts, we would be able to net payments and receipts per counterparty pursuant to the derivative contracts. Although our derivative contracts allow for netting, which would allow for recording assets and liabilities per counterparty on a net basis, we have historically accounted for our derivative contracts on a gross basis per contract as either an asset or liability. For the open derivative contracts as of December 31, 2015, there would have been no difference if the contracts were presented on net basis. There were no open derivative contracts as of December 31, 2014.

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

7. Long-Term Debt

As of December 31, 2015 and 2014, our long-term debt was as follows (in thousands):

	December 31,	
	2015	2014
8.50% Senior Notes:		
Principal	\$ 900,000	\$ 900,000
Debt premiums, net of amortization	10,503	13,057
Debt issuance costs, net of amortization	(6,274)	(7,937)
9.00% Term Loan:		
Principal	300,000	—
Debt discounts, net of amortization	(2,689)	—
Debt issuance costs, net of amortization	(4,685)	—
Revolving bank credit facility	—	447,000
Total long-term debt	1,196,855	1,352,120
Current maturities of long-term debt	—	—
Long term debt, less current maturities	<u>\$ 1,196,855</u>	<u>\$ 1,352,120</u>

Aggregate annual maturities of long-term debt as of December 31, 2015 are as follows (in millions): 2016—\$0.0; 2017—\$0.0; 2018—\$0.0; 2019—\$900.0; thereafter—\$300.0.

Senior Notes

At December 31, 2015 and 2014, our outstanding senior notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019 (the “8.50% Senior Notes”), were classified as long-term at their carrying value. Interest on the 8.50% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the 8.50% Senior Notes is 8.4%, which includes amortization of debt issuance costs and premiums. We and our restricted subsidiaries are subject to certain covenants under the indenture governing the 8.50% Senior Notes, which limit our and our restricted subsidiaries’ ability to, among other things, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of our assets, engage in transactions with affiliates, pay dividends or make other distributions on capital stock or subordinated indebtedness and create unrestricted subsidiaries. We were in compliance with those covenants as of December 31, 2015. See Note 1 related to a change in the classification of unamortized debt issuance costs on the Consolidated Balance Sheets.

Term Loan

In May 2015, we entered into the 9.00% Term Loan, which bears an annual interest rate of 9.00%, was issued at a 1% discount to par and matures on May 15, 2020. The 9.00% Term Loan is secured by a second priority lien covering our oil and gas properties to the extent such properties secure first priority liens granted to secure indebtedness under our Credit Agreement. Interest on the 9.00% Term Loan is payable in arrears semi-annually on May 15 and November 15. The estimated annual effective interest rate on the 9.00% Term Loan is 9.7%, which includes amortization of debt issuance costs and discounts. The net proceeds were used to repay a portion of the outstanding borrowings incurred under our revolving bank credit facility governed by the Credit Agreement. We are subject to various covenants under the terms governing the 9.00% Term Loan including, without limitation, covenants that limit our ability to incur other debt, pay dividends or distributions on our equity, merge or consolidate with other entities and make certain investments in other entities. We were in compliance with those covenants as of December 31, 2015. See Note 1 related to a change in the classification of unamortized debt issuance costs on the Consolidated Balance Sheets.

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

Credit Agreement

The Credit Agreement, as amended, provides a revolving bank credit facility. Availability under the Credit Agreement is subject to a semi-annual borrowing base determination set at the discretion of our lenders, and the Company and the lenders may each request one additional determination per year. The borrowing base as of December 31, 2015 was \$350.0 million. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base, such excess or deficiency is required to be repaid within 90 days in three equal monthly payments. Letters of credit may be issued in amounts up to \$300.0 million, provided availability under the revolving bank credit facility exists. The revolving bank credit facility is secured and is collateralized by our oil and natural gas properties. The Credit Agreement terminates on November 8, 2018.

The Credit Agreement contains covenants that limit, among other things, our ability to: (i) pay cash dividends; (ii) repurchase our common stock or outstanding 8.50% Senior Notes or outstanding 9.00% Term Loan, provided that such limitation will not apply to the repurchase of our existing 8.50% Senior Notes or 9.00% Term Loan in an aggregate principal amount equal to the aggregate principal amount of any new issuance of such debt; (iii) sell our assets; (iv) make certain loans or investments; (v) merge or consolidate; (vi) eliminate certain hedging contracts or enter into certain hedging contracts in excess of 75% of projected oil and gas production on a monthly basis; (vii) enter into certain liens; and (viii) enter into certain other transactions, without the prior consent of the lenders. We are permitted to issue additional indebtedness if certain conditions are met including: (i) the additional debt is subordinate in security and right of payment; (ii) the borrowers enter into an intercreditor agreement with terms acceptable to the Administrative Agent of the Credit Agreement; (iii) we are in compliance with the financial covenants after giving pro forma effect to the additional unsecured indebtedness; and (iv) such additional unsecured indebtedness matures after the maturity date of the Credit Agreement and is not subject to restrictive covenants materially more onerous than those provided for in the Credit Agreement. We are permitted to redeem, repurchase, prepay or defease all or a portion of the 8.50% Senior Notes or the 9.00% Term loan if after giving effect of such redemption, repayment, prepayment or defeasance: (i) no amounts are outstanding on the revolving bank credit facility; (ii) letters of credit outstanding do not exceed \$100.0 million; (iii) the then borrowing base is at least \$200.0 million; and (iv) no event of default shall have occurred and be continuing, and no borrowing base deficiency shall have occurred and be continuing or result therefrom.

The Credit Agreement also contains various customary covenants for certain financial tests, as defined in the Credit Agreement and measured as of the end of each quarter, and for customary events of default. These financial test ratios and limits as of December 31, 2015 and thereafter are: (i) the First Lien leverage Ratio must be less than 1.50 to 1.00; (ii) the Current Ratio must be greater than 0.75 to 1.00 as of December 31, 2015 and must be greater than 1.00 to 1.00 thereafter; and (iii) the Secured Debt Leverage Ratio must be less than 3.50 to 1.00. The customary events of default include: (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due; (ii) bankruptcy or insolvency with respect to the Company or any of its subsidiaries guaranteeing borrowings under the revolving bank credit facility; or (iii) a change of control. The Credit Agreement contains cross-default clauses with the 8.50% Senior Notes and the 9.00% Term, and these agreements contain similar cross-default clauses with the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2015.

Borrowings under the revolving bank credit facility bear interest at the applicable London Interbank Offered Rate ("LIBOR") plus a margin that varies from 2.25% to 3.25% depending on the level of total borrowings under the Credit Agreement, or an alternative base rate equal to the greater of (a) Prime Rate, (b) Federal Funds Rate plus 0.5%, and (c) LIBOR plus 1.0%, plus applicable margin ranging from 1.25% to 2.25%. The unused portion of the borrowing base is subject to a commitment fee ranging from 0.375% to 0.5%. The estimated annual effective interest rate was 3.3% for 2015 for borrowings under the Credit Agreement. The estimated annual effective interest rate includes amortization of debt issuance costs and excludes commitment fees and other costs.

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

During 2015, the borrowing base under the Credit Agreement was reduced to \$350.0 million. The reduction in the borrowing base resulted in proportional reduction in the unamortized costs related to the Credit Agreement of \$3.2 million, which is included in the line *Other (income)/expense, net* on the Consolidated Statements of Operations.

At December 31, 2015, we had no borrowings and \$0.9 million in letters of credit outstanding under the revolving bank credit facility. At December 31, 2014, we had \$447.0 million in borrowings and \$0.6 million in letters of credit outstanding under the revolving bank credit facility. See Note 20 for borrowings outstanding subsequent to December 31, 2015.

For information about fair value measurements of our long-term debt, refer to Note 8.

8. Fair Value Measurements

Under GAAP, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset should reflect its highest and best use by market participants, whether using an in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, the Company's credit risk.

Valuation techniques are generally classified into three categories: the market approach; the income approach; and the cost approach. The selection and application of one or more of these techniques requires significant judgment and is primarily dependent upon the characteristics of the asset or liability, the principal (or most advantageous) market in which participants would transact for the asset or liability and the quality and availability of inputs. Inputs to valuation techniques are classified as either observable or unobservable within the following hierarchy:

- Level 1 – quoted prices in active markets for identical assets or liabilities.
- Level 2 – inputs other than quoted prices that are observable for an asset or liability. These include: quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).
- Level 3 – unobservable inputs that reflect the Company's own expectations about the assumptions that market participants would use in measuring the fair value of an asset or liability.

The following table presents the fair value of our derivative financial instruments, our 8.50% Senior Notes, the 9.00% Term Loan and our revolving bank credit facility (in thousands):

	Hierarchy	December 31, 2015		December 31, 2014
		Assets	Liabilities	Liabilities
Derivatives	Level 2	\$ 7,672	\$ —	\$ —
8.50% Senior Notes	Level 2	—	324,000	594,000
9.00% Term Loan	Level 2	—	217,500	—
Revolving bank credit facility	Level 2	—	—	447,000

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

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 and the 9.00% Term Loan is based on quoted prices, although the market is not an active market; therefore, the fair value is classified within Level 2. The carrying amount of debt under our revolving bank credit facility approximates fair value because the interest rates are variable and reflective of market rates.

Derivatives are reported in the statement of financial position at fair value. The 8.50% Senior Notes are reported in the statement of financial position at their carrying value, which was \$900.0 million at December 31, 2015 and 2014. The 9.00% Term Loan is reported in the statement of financial position at its carrying value, which was \$300.0 million at December 31, 2015. The revolving bank credit facility debt is reported in the statement of financial position at its carrying value, which was zero and \$447.0 million at December 31, 2015 and 2014, respectively.

For additional information about our derivative financial instruments refer to Note 6 and for additional information on our 8.50% Senior Notes, the 9.00% Term Loan and revolving bank credit facility refer to Note 7.

9. Equity Structure and Transactions

As of December 31, 2015 and 2014, the Company was authorized to issue 20 million shares of preferred stock with a par value of \$0.00001 per share; however, no preferred shares have been issued or were outstanding as of the respective dates.

During 2015, we did not pay any dividends and dividends were suspended. During 2014 and 2013, we paid regular cash dividends of \$0.40 and \$0.36 per common share, respectively. In December 2013, we paid a special dividend of \$0.42 per share or \$31.8 million.

10. Incentive Compensation Plan and Directors Compensation Plan

Incentive Compensation Plan

In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (the "Plan") was approved by our shareholders and amendments to the Plan were approved by our shareholders in 2013. The Plan covers the Company's eligible employees and consultants. In addition to other cash and share-based compensation awards, the Plan is designed to grant awards that qualify as performance-based compensation within the meaning of section 162(m) of the IRC. The Plan grants the Compensation Committee of the Board of Directors administrative authority over all participants, and grants the President and Chief Executive Officer with authority over the administration of awards granted to participants that are not subject to section 16 of the Exchange Act (as applicable, the "Committee").

Pursuant to the terms of the Plan, the Committee establishes the performance criteria and may use a single measure or combination of business measures as described in the Plan. Also, individual goals may be established by the Committee. Performance awards may be granted in the form of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, or other awards related to stock, and awards may be paid in cash, stock, or any combination of cash and stock, as determined by the Committee. The performance awards granted under the Plan can be measured over a performance period of up to 10 years and annual incentive awards (a type of performance award) will generally be paid within 90 days following the applicable year end.

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

Share-based Awards: Restricted Stock Units

For 2015, 2014 and 2013, performance awards under the Plan were granted in the form of restricted stock units (“RSUs”). As defined by the Plan, RSUs are rights to receive stock, cash or a combination thereof at the end of a specified vesting period, subject to certain terms and conditions as determined by the Committee. 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 using a predefined scale based on the Company achieving certain predetermined performance criteria. Vesting occurs upon completion of the specified vesting period applicable to each grant. Subsequent to the determination of the performance achievement and prior to vesting, the RSUs earn dividend equivalents at the same rate as dividends paid on our common stock. RSUs are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted period.

During 2015, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) net income before income tax expense, net interest expense, depreciation, depletion, amortization, accretion and certain other items (“Adjusted EBITDA”) for 2015 and (ii) Adjusted EBITDA as a percent of total revenue (“Adjusted EBITDA Margin”) for 2015. Adjustments range from 0% to 100% based upon actual results compared against pre-defined performance levels. For 2015, the Company was below target for Adjusted EBITDA and above target for Adjusted EBITDA Margin.

During 2014, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA for 2014 and (ii) Adjusted EBITDA Margin for 2014. Adjustments range from 0% to 100% based upon actual results compared against pre-defined performance levels. For 2014, the Company was above target for Adjusted EBITDA and was slightly below target for Adjusted EBITDA Margin.

During 2013, RSUs granted were subject to a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA for 2013; (ii) Adjusted EBITDA Margin for 2013; and (iii) the Company’s total shareholder return (“TSR”) ranking against peer companies’ TSR for 2013, 2014 and January 1, 2015 to October 31, 2015. TSR is determined based upon the change in the entity’s stock price plus dividends for the applicable performance period. Adjustments range from 0% to 150% for portions subject to Adjusted EBITDA and Adjusted EBITDA Margin measurements and adjustments range from 0% to 200% for the portion subject to TSR measurement. For 2013, the Company exceeded the target for Adjusted EBITDA and was approximately at target for 2013 Adjusted EBITDA Margin. For the 2015, 2014 and 2013 periods, the Company was below target for the TSR rankings for each period. In addition, RSUs were granted during 2013 which were not subject to performance criteria and were less than 3% of total grants.

All RSUs granted to date are subject to employment-based criteria in addition to performance criteria. Vesting occurs in December of the second calendar year following the date of grant. For example, the RSUs granted during 2013 (after adjustment for performance) vested in December 2015 to eligible employees.

Cash-based Awards

For 2015, 2014 and 2013, cash-based awards were granted under the Plan to substantially all eligible employees. The cash-based awards, which are a short-term component of the Plan, were determined based on multiple performance measures, such as Adjusted EBITDA, reserve and production growth, cost containment and individual performance measures. With respect to the 2015 cash-based awards, some of the performance criteria targets were achieved and were combined with estimates of personal performance measurements to record potential payments. In addition, for the 2015 cash-based awards, which includes the 2015 incentive plan for the Chief Executive Officer (“CEO”), the Company designed the awards with an additional financial condition that must be achieved on or before December 31, 2017: Adjusted EBITDA less Interest Expense Incurred, as reporting by the Company in its announced Earning Release with respect to the end of any fiscal quarter plus three preceding quarters, exceeds \$300.0 million. As this additional financial condition was not achieved as of December 31, 2015, no amounts were accrued or subsequently paid. If this additional financial condition is achieved, payment is to be made within 30 days following the achievement of the financial condition, but subject to all the terms of the 2015 Annual Incentive Award Agreement (the 2015 cash-based award).

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

With respect to the 2014 cash-based awards, some of the performance criteria targets were achieved and were combined with estimates of personal performance measurements to record potential payments. With respect to the 2013 cash-based awards, most of the performance criteria targets were achieved and were combined with the individual's performance to determine the cash-based award. With respect to the 2012 cash-based awards, some of the performance criteria targets were achieved and were combined with the individual's performance to determine the cash-based award. In addition, pursuant to the Plan, discretionary authority was exercised for certain non-executive employees, which increased cash-based award amounts in 2012. Eligible employees were paid their cash-based awards within 75 days following year end.

Share-based Awards: Common Stock

The 2014 annual incentive plan award for the CEO was settled in shares of common stock based on a pre-determined price of \$14.66 per share, pursuant to the terms of his award. As the number of shares could not be determined until the full-year 2014 results were determined and approved by the Compensation Committee, the CEO's 2014 award was accounted for as a liability award during 2014 and adjusted to fair value using the company's closing price at the end of each reporting period. The 2013 annual incentive award for the CEO was settled in shares of common stock based at the price of \$14.84, which was the Company's closing price the day prior to the settlement date. The CEO awards for both years were 100% performance based and were subject to pre-defined performance measures and employment-based criteria, which were the same pre-defined performance measures and employment-based criteria established for the other eligible Company employees, and were subject to approval of the Compensation Committee.

Directors Compensation Plan Share-Based Awards

Under the Directors Compensation Plan, shares of restricted stock ("Restricted Shares") were issued in 2015, 2014 and 2013 to the Company's non-employee directors as a component of their compensation arrangement. Vesting occurs upon completion of the specified vesting period and one-third of each grant vests each year over a three-year 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. Restricted Shares are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restriction period.

For additional information concerning share-based awards and cash-based awards, including expense recognition, see Note 11.

11. Share-Based and Cash-Based Incentive Compensation

As allowed by the Plan, in 2015, 2014 and 2013, the Company granted RSUs to certain of its employees. In 2015, 2014 and 2013, restricted stock was granted to the Company's non-employee directors under the Directors Compensation Plan. In addition to share-based compensation, the Company granted cash-based incentive awards to substantially all eligible employees in 2015, 2014 and 2013.

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. As of December 31, 2015, there were 4,239,548 shares of common stock available for issuance in satisfaction of awards under the Plan and 444,024 shares of common stock available for issuance in satisfaction of awards under the Directors Compensation Plan. The shares available for both plans are reduced when restricted stock is granted. RSUs reduce the shares available in the Plan only when RSUs are settled in shares of common stock, net of withholding tax. Although the Company has the option to settle RSUs in stock or cash at vesting, only common stock has been used to settle vested RSUs to date.

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

Restricted Stock

Under the Directors Compensation Plan, shares of restricted stock ("Restricted Shares") were issued in 2015, 2014 and 2013 to the Company's non-employee directors. See Note 10 for additional information concerning Restricted Shares. A summary of activity related to Restricted Shares is as follows:

	2015		2014		2013	
	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Nonvested, beginning of period	43,210	\$ 16.20	43,840	\$ 15.96	43,687	\$ 18.69
Granted	56,540	6.19	18,815	18.60	27,450	12.75
Vested	(21,520)	16.26	(19,445)	18.00	(27,297)	17.09
Nonvested, end of period	78,230	\$ 8.95	43,210	\$ 16.20	43,840	\$ 15.96

Subject to the satisfaction of service conditions, the Restricted Shares outstanding as of December 31, 2015 are expected to vest as follows:

	Restricted Shares
2016	34,265
2017	25,115
2018	18,850
Total	78,230

Restricted stock fair value at grant date: The grant date fair value of restricted stock granted during 2015, 2014 and 2013 was \$0.3 million for all periods based on the Company's closing price on the date of grant.

Restricted stock fair value at vested date: The fair value of the restricted stock that vested during 2015, 2014 and 2013 was \$0.1 million, \$0.3 million and \$0.4 million, respectively, based on the Company's closing price on the date of vesting.

Restricted Stock Units

During 2015, 2014 and 2013, the Company granted RSUs to certain employees, with nearly all grants being contingent upon meeting specified performance requirements. The grants are subject to adjustments at the end of the applicable performance period using a predefined scale based on the Company achieving certain predetermined performance criteria. See Note 10 for additional information concerning RSUs.

The fair value of the RSUs granted in 2015 and 2014 was determined using the Company's closing price on the grant dates as the performance measures were all company-specific performance measures comprised of Adjusted EBITDA and Adjusted EBITDA Margin.

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

The fair value of the RSUs granted in 2013 was determined separately for each component. For the components related to the company-specific performance measures (Adjusted EBITDA and Adjusted EBITDA Margin), the fair value was determined using the Company's closing price on the grant date. The components related to Adjusted EBITDA and Adjusted EBITDA Margin comprised 40% and 30%, respectively, of the amount granted. For the component related to TSR ranking, the fair value was determined using a Monte Carlo simulation probabilistic model. The component related to TSR ranking totaled 30% of the amount granted, with 10% for each of the three-year performance periods. The inputs used in the model for the Company and the peer companies were: average closing stock prices during January 2013; risk-free interest rates using the LIBOR ranging from 0.27% to 0.91% over the service period; expected volatilities ranging from 30% to 63%; expected dividend yields ranging from 0.0% to 3.1%; and correlation factors ranging from a negative 84% to a positive 95%. The expected volatilities, expected dividends and correlation factors were developed using historical data. For the RSUs granted in 2013 that were not subject to performance measures, the fair value was determined using the closing price on the date of grant.

A summary of activity related to RSUs is as follows:

	2015		2014		2013	
	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Share	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Share	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Share
Nonvested, beginning of period	1,977,335	\$ 15.29	1,331,753	\$ 14.96	969,820	\$ 22.70
Granted	2,626,930	3.59	1,195,388	16.84	969,919	13.23
Vested	(721,038)	13.23	(354,692)	18.59	(468,925)	26.93
Forfeited	(409,148)	10.63	(195,114)	16.53	(139,061)	16.50
Nonvested, end of period	<u>3,474,079</u>	\$ 7.42	<u>1,977,335</u>	\$ 15.29	<u>1,331,753</u>	\$ 14.96

Subject to the satisfaction of service conditions, the RSUs outstanding as of December 31, 2015 are eligible to vest in the year indicated in the table below:

	Restricted Stock Units
2016	1,003,604
2017	2,470,475
Total	<u>3,474,079</u>

RSUs fair value at grant date: During 2015, 2014 and 2013, the grant date fair value of RSUs granted was \$9.4 million, \$20.1 million and \$12.8 million, respectively.

RSUs fair value at vested date: The fair value of the RSUs that vested during 2015, 2014 and 2013 was \$2.1 million, \$2.0 million and \$7.2 million, respectively, based on the Company's closing price on the vesting date.

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

Common Stock

An issuance of 37,316 shares of common stock was made in March 2015 to the CEO pursuant to the terms of his 2014 annual incentive compensation award, which valued the shares at a predetermined price. The number of shares was determined after deductions for withholding and payroll taxes and the shares were valued at the Company's closing price as of the date of issuance. A grant and issuance of 42,547 shares of common stock was made in March 2014 to the CEO pursuant to the terms of his 2013 annual incentive compensation award. The number of shares was determined after deductions for withholding and payroll taxes and the shares were valued at the Company's closing price as of the date of grant. See Note 10 for additional information concerning the CEO annual incentive compensation award.

Share-Based Compensation

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

	Year Ended December 31,		
	2015	2014	2013
Share-based compensation expense from:			
Restricted stock	\$ 358	\$ 369	\$ 397
Restricted stock units	9,978	13,150	11,128
Common shares	(94)	1,225	—
Total	<u>\$ 10,242</u>	<u>\$ 14,744</u>	<u>\$ 11,525</u>
Share-based compensation tax benefit:			
Tax benefit computed at the statutory rate	<u>\$ 3,585</u>	<u>\$ 5,160</u>	<u>\$ 4,034</u>

As of December 31, 2015, unrecognized share-based compensation expense related to our awards of Restricted Shares and RSUs was \$0.5 million and \$12.7 million, respectively. Unrecognized compensation expense will be recognized through April 2018 for restricted shares and November 2017 for RSUs.

Cash-based Incentive Compensation

As defined by the Plan, annual incentive awards payable in cash may be granted to eligible employees. 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, although the 2015 awards were designed with an additional financial condition that may be satisfied prior to December 31, 2017.

Share-Based Compensation and Cash-Based Incentive Compensation Expense

A summary of incentive compensation expense is as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Share-based compensation included in:			
General and administrative	\$ 10,242	\$ 14,744	\$ 11,525
Cash-based incentive compensation included in:			
Lease operating expense	364	3,285	3,482
General and administrative ⁽¹⁾	(233)	6,950	8,817
Total charged to operating income	<u>\$ 10,373</u>	<u>\$ 24,979</u>	<u>\$ 23,824</u>

(1) Adjustments to true up estimates to actual payments resulted in net credit balances to expense for 2015

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

12. Employee Benefit Plan

We maintain a defined contribution benefit plan in compliance with Section 401(k) of the IRC (the "401(k) Plan"), which covers those employees who meet the 401(k) Plan's eligibility requirements. During 2015, 2014 and 2013, the Company's matching contribution was 100% of each participant's contribution up to a maximum of 6% of the participant's eligible compensation, subject to limitations imposed by the IRC. The 401(k) Plan provides 100% vesting in Company match contributions on a pro rata basis over five years of service (20% per year). Our expenses relating to the 401(k) Plan were \$2.3 million, \$2.4 million and \$2.1 million for 2015, 2014 and 2013, respectively.

13. Income Taxes

Income Tax Expense (Benefit)

Components of income tax expense (benefit) were as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Current	\$ 288	\$ 301	\$ (2,146)
Deferred	(203,272)	(4,760)	30,920
	<u>\$ (202,984)</u>	<u>\$ (4,459)</u>	<u>\$ 28,774</u>

Effective Tax Rate Reconciliation

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to our income tax expense (benefit) is as follows (in thousands):

	Year Ended December 31,					
	2015		2014		2013	
Income tax expense (benefit) at the federal statutory rate	\$ (436,696)	35.0%	\$ (5,642)	35.0%	\$ 28,033	35.0%
Share-based compensation	2,940	(0.2)	—	—	—	—
State income taxes	(2,343)	0.2	263	(1.6)	343	0.4
Valuation allowance	232,925	(18.7)	—	—	—	—
Other	190	-	920	(5.7)	398	0.5
	<u>\$ (202,984)</u>	<u>16.3%</u>	<u>\$ (4,459)</u>	<u>27.7%</u>	<u>\$ 28,774</u>	<u>35.9%</u>

Our effective tax rate for the year 2015 differed from the federal statutory rate of 35.0% primarily due to recording a valuation allowance for our deferred tax assets, which is discussed below. Our effective tax rate for the year 2014 is distorted due to a small pre-tax loss; consequently, our permanent differences have a larger impact on our effective tax rate. Our effective tax rate for the year 2013 differed from the federal statutory rate primarily as a result of state income taxes.

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

Deferred Tax Assets and Liabilities

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities were as follows (in thousands):

	December 31,	
	2015	2014
Deferred tax liabilities:		
Property and equipment	\$ 40,287	\$ 518,566
Derivatives	2,697	—
Other	3,000	5,019
Total deferred tax liabilities	<u>45,984</u>	<u>523,585</u>
Deferred tax assets:		
Alternative minimum tax credit	20,486	20,486
Asset retirement obligations	133,018	137,597
Federal net operating losses	145,733	180,024
State net operating losses	5,068	5,008
Valuation allowance	(237,275)	(4,255)
Accrued cash-based bonus	—	3,559
Share-based compensation	4,245	5,042
Other	2,304	798
Total deferred tax assets	<u>73,579</u>	<u>348,259</u>
Net deferred tax asset (liabilities)	<u>\$ 27,595</u>	<u>\$ (175,326)</u>

During 2015, we did not make any payments for federal and state income taxes or receive any refunds of significance. During 2014, we did not make any payments for federal and state income taxes and we received refunds of \$3.0 million. During 2013, we made payments primarily for federal and state income taxes of approximately \$3.0 million. During 2013, we received refunds of \$59.1 million, of which \$9.5 million have been accounted for as unrecognized tax benefits. The refunds were primarily attributable to tax loss carrybacks to 2010 and 2011, and refunds of estimated tax payments.

Net Operating Loss and Tax Credit Carryovers

The table below presents the details of our net operating loss and tax credit carryovers as of December 31, 2015 (in thousands):

	Amount	Expiration Year
Federal net operating loss	\$ 418,417	2032-2035
State net operating losses	100,651	2021-2029
Alternative minimum tax credit	12,091	Indefinite
General business credit	406	2027-2028

The federal net operating loss and alternative minimum tax credit amounts presented in the table, *Deferred Tax Assets and Liabilities*, reflect adjustments for unrecognized excess tax benefits and uncertain tax positions, as applicable, to the amounts presented above.

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

Valuation Allowance

During 2015, we recorded a valuation allowance of \$232.9 million related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. As of December 31, 2015 we had a valuation allowance related to Federal, Louisiana and Alabama net operating losses and other deferred taxes. As of December 31, 2014, we had a valuation allowance related only to Louisiana net operating losses.

Uncertain Tax Positions

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits. There are no unrecognized benefits that would impact the effective tax rate if recognized. While amounts could change in the next 12 months, we do not anticipate it having a material impact on our financial statements.

Balances in the uncertain tax positions are as follows (in thousands):

	December 31,	
	2015	2014
Balance, beginning and end of period	\$ 9,482	\$ 9,482

We recognize interest and penalties related to uncertain tax positions in income tax expense. For 2015, 2014 and 2013, the amounts recognized in income tax expense were immaterial.

Years open to examination

The tax years from 2012 through 2015 remain open to examination by the tax jurisdictions to which we are subject.

14. Earnings Per Share

The Company's unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are deemed participating securities and are included in the computation of earnings per share under the two-class method.

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

	Year Ended December 31,		
	2015	2014	2013
Net income (loss)	\$ (1,044,718)	\$ (11,661)	\$ 51,322
Less portion allocated to nonvested shares	—	269	303
Net income (loss) allocated to common shares	\$ (1,044,718)	\$ (11,930)	\$ 51,019
Weighted average common shares outstanding	75,931	75,609	75,239
Basic and diluted earnings (loss) per common share	\$ (13.76)	\$ (0.16)	\$ 0.68
Shares excluded due to being anti-dilutive (weighted-average)	2,195	2,097	—

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

15. Supplemental Cash Flow Information

The following reflects our supplemental cash flow information (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Cash paid for interest, net of interest capitalized of \$7,256 in 2015, \$8,526 in 2014 and \$10,058 in 2013	\$ 92,622	\$ 77,607	\$ 73,909
Cash paid for income taxes	390	—	3,000
Cash refunds received for income taxes	90	3,000	59,126
Cash paid for share-based compensation ⁽¹⁾	—	431	466

- (1) The cash paid for share-based compensation is for dividends on unvested restricted stock and for dividend equivalents paid on RSUs. No cash was received from employees or directors related to share-based compensation and no cash was used to settle any equity instruments granted under share-based compensation arrangements.

16. Commitments

We have operating lease agreements for office space and office equipment. The lease for the majority of our office space terminates in December 2022. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2015 are as follows: 2016—\$1.6 million; 2017—\$1.6 million; 2018—\$1.7 million; 2019—\$1.8 million thereafter—\$5.7 million. Total rent expense was approximately \$3.3 million, \$3.2 million and \$2.6 million during 2015, 2014 and 2013, respectively.

Pursuant to the Purchase and Sale Agreement with Total E&P, we are required to fulfill security requirements related to ARO for certain properties through bonds or making payments to an escrow account or a combination. As of December 31, 2015, we were in compliance with the security amount requirement of \$73.0 million. Additional security requirements are \$6.0 million in 2016, \$4.0 million in 2017, \$5.0 million in 2018, \$3.0 million in 2019 and \$12.0 million in the 2020 to 2023 time period to a total security requirement of \$103.0 million by 2023.

Pursuant to the Purchase and Sale agreement with Shell Offshore Inc. (“Shell”) related to ARO for certain properties, we have bonds that are subject to re-appraisal by either party after November 2015. As of December 31, 2015, neither party had requested a re-appraisal to be made. The current security requirement of \$64.0 million could be increased up to \$94.0 million depending on certain conditions and circumstances.

During 2015, 2014 and 2013, we had surety bonds related to our decommissioning obligations or ARO, with the BOEM named as beneficiary. See Note 20 for information concerning a demands received by the BOEM in February and March 2016.

Total expenses related to surety bonds, inclusive of the surety bonds in connection with Total E&P, Shell and the BOEM described above, were \$5.5 million, \$4.1 million and \$5.0 million during 2015, 2014 and 2013, respectively. The amount of future commitments is dependent on rates charged in the market place and when asset retirements are completed. Estimated future expenses related to surety bonds were based on current market prices and estimates of the timing of asset retirements, of which some wells and structures are estimated to extend to 2030. Future costs are estimated as follows: 2016—\$5.8 million; 2017—\$5.9 million; 2018—\$5.3 million; 2019—\$5.0 million; thereafter—\$30.4 million. See Note 20 for information concerning a demand received by the BOEM in February and March 2016, which will impact future cost estimates related to surety bonds.

Pursuant to an agreement with the Helix Well Containment Group, we are required to make payments to have access to certain equipment to respond to a subsea spill should a spill occur at a property we operate. As of December 31, 2015, future payments due are \$2.1 million in 2016 and \$2.1 million in 2017. These payments may increase or decrease depending on whether the number of companies participating in the consortium changes.

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

We have no drilling rig commitments with a term that exceeded one year as of December 31, 2015 and our drilling rig commitments meet the criteria of an operating lease. Future payments of all drilling rig commitments as of December 31, 2015 were \$7.0 million.

17. Related Parties

During 2015, 2014 and 2013, there were certain transactions between us and other companies our majority shareholder either controlled or in which he had an ownership interest. In addition, there were transactions with a company that employs the spouse of our majority shareholder. Our majority shareholder owns an aircraft that the Company used and reimbursed him for such use and for his use. Airplane services were charged to us at rates that were either equal to or below rates charged by non-related, third-party companies. Airplane services transactions were approximately \$1.1 million, \$0.9 million and \$1.2 million for the years 2015, 2014 and 2013, respectively. Our majority shareholder has ownership interests in certain wells operated by us (such ownership interests pre-date our initial public offering). Revenues are disbursed and expenses are collected in accordance with ownership interest. Proportionate insurance premiums were paid to us and proportionate collections of insurance reimbursements attributable to damage on certain wells were disbursed. W&T hired the services of a directional drilling services company, in which our majority shareholder owns a minority ownership interest and serves on its board of directors, and W&T paid no amounts in 2015 and paid \$0.2 million and \$0.2 million for drilling related services during 2014 and 2013, respectively. A company that provides marine transportation and logistics services to W&T employs the spouse of our majority shareholder. The spouse received commissions partially based on services rendered to W&T which totaled less than \$0.2 million per year for 2015, 2014 and 2013. During 2015, an entity controlled by our majority shareholder participated in the 9.00% Term Loan for a \$5.0 million principal commitment on the same terms as the other lenders.

18. Contingencies

Supplemental bonding requirements by the BOEM

The significant reductions in crude oil and natural gas pricing since the middle of 2014 have adversely impacted our financial strength and have resulted in our inability to meet the relevant financial strength and reliability criteria set forth in the BOEM Notice To Lessee #2008-N07, *Supplemental Bond Procedures*, (“NTL #2008-N07”). Since both W&T Offshore, Inc. and its subsidiary are now subject to supplemental bonding, we had discussions with the BOEM during 2015. See Note 20 for information concerning demands received by the BOEM in February and March 2016.

The issuers of such surety bonds may request, and in some cases, have requested, collateral, which could be significant and could impact our liquidity. In addition, pursuant to the terms of our agreements with various sureties under our existing bonds or under any additional bonds we may obtain, we are required to post collateral at any time, on demand, at the surety’s discretion.

Notification by ONRR of Fine for Non-compliance

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

Apache Lawsuit

On December 15, 2014, Apache Corporation (“Apache”) filed a lawsuit against W&T Offshore, Inc., alleging that W&T breached the joint operating agreement (“JOA”) related to deepwater wells in the Mississippi Canyon area of the Gulf of Mexico. That lawsuit, styled *Apache Corporation v. W&T Offshore, Inc.*, is currently pending in the United States District Court for the Southern District of Texas. Apache contends that W&T has failed to pay its proportional share of the costs associated with plugging and abandoning three wells that are subject to the JOA. We contend that the costs incurred by Apache are excessive and unreasonable. Apache seeks an award of unspecified actual damages, interest, court costs, and attorneys’ fees. In February 2015, we made a payment to Apache for our net share of the amounts that we believe are reasonable to plug and abandon the three wells, all of which was originally recorded as an asset retirement obligation and was accrued on our balance sheet as of December 31, 2014. Our estimate of the potential exposure ranges from zero to \$32 million related to this matter, which excludes potential interest, court costs and attorney fees.

Insurance Claims

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

Royalties

In 2009, the Company recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited the calculations and support related to this usage fee, and in 2010, we were notified that the ONRR had disallowed approximately \$4.7 million of the reductions taken. We recorded a reduction to other revenue in 2010 to reflect this disallowance; however, we disagree with the position taken by the ONRR. We filed an appeal with the ONRR, which was denied in May 2014. On June 17, 2014, we filed an appeal with the Board of Land Appeals (the “BLA”) under the Department of the Interior. W&T’s brief was filed in November 2014 and we expect the briefing before BLA to be completed in 2016.

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

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

Notices of Proposed Civil Penalty Assessment

During 2015, the Company received four final notices from the BSEE of civil penalties related to Incidents of Noncompliance (“INCs”) at various offshore locations. An aggregate \$0.2 million has been paid in respect of three of the four final notices. The Company also received three proposed notices from BSEE related to INCs at various offshore locations. The occurrence dates range from June 2012 to June 2014. For the unpaid proposed penalties, the Company has accrued approximately \$1.0 million as of December 31, 2015, which is the Company’s best estimate of the final settlement once all appeals have been exhausted. The proposed amounts by the BSEE for the unpaid proposed penalties totaled \$8.1 million. The Company’s position is that the proposed civil penalties are excessive given the specific facts and circumstances related to the INCs.

Iberville School Board Lawsuit

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

Other Claims

We are a party to various pending or threatened claims and complaints seeking damages or other remedies concerning our commercial operations and other matters in the ordinary course of our business. In addition, claims or contingencies may arise related to matters occurring prior to our acquisition of properties or related to matters occurring subsequent to our sale of properties. In certain cases, we have indemnified the sellers of properties we have acquired, and in other cases, we have indemnified the buyers of properties we have sold. We are also subject to federal and state administrative proceedings conducted in the ordinary course of business including matters related to alleged royalty underpayments on certain federal-owned properties. Although we can give no assurance about the outcome of pending legal and federal or state administrative proceedings and the effect such an outcome may have on us, we believe that any ultimate liability resulting from the outcome of such proceedings, to the extent not otherwise provided for or covered by insurance, will not have a material adverse effect on our consolidated financial position, results of operations or liquidity.

Contingent Liability Recorded

There was no material expenses recognized related to accrued and settled claims, complaints and fines for 2015, 2014 or 2013. As of December 31, 2015 and 2014, we had no material amounts recorded in liabilities for claims, complaints and fines.

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

19. Selected Quarterly Financial Data—UNAUDITED

Unaudited quarterly financial data are as follows (in thousands, except per share amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2015				
Revenues	\$ 127,907	\$ 149,066	\$ 126,228	\$ 104,064
Operating loss (1)	(337,508)	(278,806)	(468,573)	(60,816)
Net loss (1)	(255,095)	(260,449)	(477,568)	(51,606)
Basic and diluted loss per common share(1) (2)	(3.36)	(3.43)	(6.29)	(0.68)
Year Ended December 31, 2014				
Revenues	\$ 254,516	\$ 262,994	\$ 234,521	\$ 196,677
Operating income (loss)	37,225	34,403	20,983	(30,543)
Net income (loss)	11,189	9,837	684	(33,371)
Basic and diluted earnings (loss) per common share(2)	0.15	0.13	0.01	(0.44)

- (1) During 2015, we recorded in first, second, third and fourth quarter ceiling test write-downs of oil and natural gas properties of \$260.4 million, \$252.8 million, \$441.6 million and \$32.4 million, respectively. See Note 1 for additional information.
- (2) The sum of the individual quarterly earnings (loss) per share may not agree with the year loss per share because each quarterly calculation is based on the income for that quarter and the weighted average number of shares outstanding during that quarter.

20. Subsequent Events

On February 26, 2016, we announced that we had borrowed \$340.0 million under the Credit Agreement for general corporate purposes. Our cash balance after the borrowing was approximately \$447.0 million and \$9.1 million was the remaining availability under the Credit Agreement.

In February and March 2016, we received several demands from the BOEM ordering the Company to secure financial assurances in the form of additional surety bonds in the aggregate of \$260.8 million to cover our decommissioning obligations under certain Federal offshore oil and gas leases and rights of way operated by us. The bonds are to be secured on or before March 29, 2016. The issuance of any additional surety bonds to satisfy this order could require the posting of cash collateral or letters of credit, which could be substantial. The BOEM demand states that failure to comply with their order may result in the BOEM taking enforcement action, which includes assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases. We intend to continue discussions with the BOEM to resolve our issues concerning supplemental financial assurances, and if after review of this order the Company deems it necessary and appropriate, we may exercise our rights to appeal to the Interior Board of Land Appeals or otherwise challenge this order.

21. Supplemental Guarantor Information

Our payment obligations under the 8.50% Senior Notes, the 9.00% Term Loan and the Credit Agreement (see Note 7) are fully and unconditionally guaranteed by our 100%-owned subsidiaries, W & T Energy VI, LLC and W & T Energy VII, LLC (together, the "Guarantor Subsidiaries"). W & T Energy VII, LLC does not currently have any active operations or contain any assets. Guarantees of the 8.50% Senior Notes will be released under certain circumstances, including:

- (1) in connection with any sale or other disposition of all or substantially all of the assets of a Guarantor Subsidiary (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary (as such term is defined in the indenture governing the 8.50% Senior Notes) of the Company, if the sale or other disposition does not violate the Asset Sales provisions (as such terms are defined in certain debt documents);
- (2) in connection with any sale or other disposition of the capital stock of such Guarantor Subsidiary to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the Asset Sales provisions of certain debt documents and the Guarantor Subsidiary ceases to be a subsidiary of the Company as a result of such sales or disposition;
- (3) if such Guarantor Subsidiary is a Restricted Subsidiary and the Company designates such Guarantor Subsidiary as an Unrestricted Subsidiary in accordance with the applicable provisions of certain debt documents;
- (4) upon Legal Defeasance or Covenant Defeasance (as such terms are defined in certain debt documents) or upon satisfaction and discharge of the indenture;
- (5) upon the liquidation or dissolution of such Guarantor Subsidiary, provided no event of default has occurred and is continuing; or
- (6) at such time as such Guarantor Subsidiary is no longer required to be a Guarantor Subsidiary as described in certain debt documents, provided no event of default has occurred and is continuing.

The following condensed consolidating financial information presents the financial condition, results of operations and cash flows of the Parent Company and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company's results on a consolidated basis. Included in the consolidating adjustments was an adjustment related to the ceiling test write-down, as the computation is performed for each subsidiary on a stand-alone basis and also for the consolidated Company. This resulted in write-downs for the combined subsidiaries to be greater than computed on a total Company basis, which required a contra ceiling test write-down adjustment to present the consolidated results appropriately.

When transfers of property were made from the Parent Company to the Guarantor Subsidiaries, which were transactions between entities under common control, the prior period financial information was retrospectively adjusted for comparability purposes, as prescribed under authoritative guidance. None of the adjustments had any effect on the consolidated results for the current or prior periods presented.

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

Condensed Consolidating Balance Sheet as of December 31, 2015
(In thousands)

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

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

Condensed Consolidating Balance Sheet as of December 31, 2014
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Assets				
Current assets:				
Cash and cash equivalents	\$ 23,666	\$ —	\$ —	\$ 23,666
Receivables:				
Oil and natural gas sales	41,820	25,422	—	67,242
Joint interest and other	142,885	—	(99,240)	43,645
Total receivables	184,705	25,422	(99,240)	110,887
Prepaid expenses and other assets	28,728	7,619	—	36,347
Total current assets	237,099	33,041	(99,240)	170,900
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,038,915	2,006,751	—	8,045,666
Furniture, fixtures and other	23,269	—	—	23,269
Total property and equipment	6,062,184	2,006,751	—	8,068,935
Less accumulated depreciation, depletion and amortization	4,442,899	1,132,179	—	5,575,078
Net property and equipment	1,619,285	874,572	—	2,493,857
Restricted deposits for asset retirement obligations	15,444	—	—	15,444
Other assets	966,112	357,992	(1,314,797)	9,307
Total assets	<u>\$ 2,837,940</u>	<u>\$ 1,265,605</u>	<u>\$ (1,414,037)</u>	<u>\$ 2,689,508</u>
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	\$ 188,654	\$ 5,455	\$ —	\$ 194,109
Undistributed oil and natural gas proceeds	36,130	879	—	37,009
Asset retirement obligations	30,711	5,292	—	36,003
Accrued liabilities	17,437	99,180	(99,240)	17,377
Total current liabilities	272,932	110,806	(99,240)	284,498
Long-term debt, less current maturities	1,352,120	—	—	1,352,120
Asset retirement obligations, less current portion	235,876	118,689	—	354,565
Deferred income taxes	49,819	125,507	—	175,326
Other liabilities	417,885	—	(404,194)	13,691
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	414,580	703,440	(703,440)	414,580
Retained earnings	118,894	207,163	(207,163)	118,894
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	509,308	910,603	(910,603)	509,308
Total liabilities and shareholders' equity	<u>\$ 2,837,940</u>	<u>\$ 1,265,605</u>	<u>\$ (1,414,037)</u>	<u>\$ 2,689,508</u>

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

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2015
(In thousands)

	<u>Parent Company</u>	<u>Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated W&T Offshore, Inc.</u>
Revenues	\$ 290,212	\$ 217,053	\$ —	\$ 507,265
Operating costs and expenses:				
Lease operating expenses	126,189	66,576	—	192,765
Production taxes	3,002	—	—	3,002
Gathering and transportation	9,209	7,948	—	17,157
Depreciation, depletion and amortization	201,154	172,214	—	373,368
Asset retirement obligations accretion	11,587	9,116	—	20,703
Ceiling test write-down of oil and natural gas properties	616,947	517,880	(147,589)	987,238
General and administrative expenses	39,009	34,101	—	73,110
Derivative gain	(14,375)	—	—	(14,375)
Total costs and expenses	<u>992,722</u>	<u>807,835</u>	<u>(147,589)</u>	<u>1,652,968</u>
Operating loss	(702,510)	(590,782)	147,589	(1,145,703)
Loss of affiliates	(464,931)	—	464,931	—
Interest expense:				
Incurred	101,542	3,050	—	104,592
Capitalized	(4,206)	(3,050)	—	(7,256)
Other (income) expense, net	4,663	—	—	4,663
Loss before income tax benefit	(1,269,440)	(590,782)	612,520	(1,247,702)
Income tax benefit	(77,133)	(125,851)	—	(202,984)
Net loss	<u>\$ (1,192,307)</u>	<u>\$ (464,931)</u>	<u>\$ 612,520</u>	<u>\$ (1,044,718)</u>

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

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2014
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Revenues	\$ 571,365	\$ 377,343	\$ —	\$ 948,708
Operating costs and expenses:				
Lease operating expenses	180,149	84,602	—	264,751
Production taxes	7,932	—	—	7,932
Gathering and transportation	11,790	8,031	—	19,821
Depreciation, depletion, amortization and accretion	267,406	223,063	—	490,469
Asset retirement obligations accretion	10,981	9,652	—	20,633
General and administrative expenses	46,513	40,486	—	86,999
Derivative loss	(3,965)	—	—	(3,965)
Total costs and expenses	520,806	365,834	—	886,640
Operating income	50,559	11,509	—	62,068
Earnings of affiliates	8,320	—	(8,320)	—
Interest expense:				
Incurred	84,460	2,462	—	86,922
Capitalized	(6,064)	(2,462)	—	(8,526)
Other (income) expense, net	(208)	—	—	(208)
Income (loss) before income tax expense	(19,309)	11,509	(8,320)	(16,120)
Income tax expense (benefit)	(7,648)	3,189	—	(4,459)
Net income (loss)	\$ (11,661)	\$ 8,320	\$ (8,320)	\$ (11,661)

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

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2013
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Revenues	\$ 631,267	\$ 352,821	\$ —	\$ 984,088
Operating costs and expenses:				
Lease operating expenses	202,096	68,743	—	270,839
Production taxes	7,135	—	—	7,135
Gathering and transportation	9,248	8,262	—	17,510
Depreciation, depletion and amortization	236,600	194,011	—	430,611
Asset retirement obligations accretion	14,218	6,700	—	20,918
General and administrative expenses	44,040	37,834	—	81,874
Derivative loss	8,470	—	—	8,470
Total costs and expenses	521,807	315,550	—	837,357
Operating income	109,460	37,271	—	146,731
Earnings of affiliates	24,400	—	(24,400)	—
Interest expense:				
Incurred	82,570	3,069	—	85,639
Capitalized	(6,989)	(3,069)	—	(10,058)
Other (income) expense, net	(8,946)	—	—	(8,946)
Income before income tax expense	67,225	37,271	(24,400)	80,096
Income tax expense	15,903	12,871	—	28,774
Net income	<u>\$ 51,322</u>	<u>\$ 24,400</u>	<u>\$ (24,400)</u>	<u>\$ 51,322</u>

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

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2015
(In thousands)

	<u>Parent Company</u>	<u>Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated W&T Offshore, Inc.</u>
Operating activities:				
Net loss	\$ (1,192,307)	\$ (464,931)	\$ 612,520	\$ (1,044,718)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion, amortization and accretion	212,741	181,330	—	394,071
Ceiling test write-down of oil and gas properties	616,947	517,880	(147,589)	987,238
Debt issuance costs write-off/amortization of debt items	4,411	—	—	4,411
Share-based compensation	10,242	—	—	10,242
Derivative gain	(14,375)	—	—	(14,375)
Cash receipts on derivative settlements, net	6,703	—	—	6,703
Deferred income taxes	(77,421)	(125,851)	—	(203,272)
Loss of affiliates	464,931	—	(464,931)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	39,078	(6,842)	—	32,236
Joint interest and other receivables	21,633	—	—	21,633
Income taxes	(7)	—	—	(7)
Prepaid expenses and other assets	(13,916)	122,977	(91,245)	17,816
Asset retirement obligation settlements	(26,637)	(5,918)	—	(32,555)
Accounts payable, accrued liabilities and other	(142,270)	4,156	91,245	(46,869)
Net cash provided by (used in) operating activities	<u>(90,247)</u>	<u>222,801</u>	<u>—</u>	<u>132,554</u>
Investing activities:				
Investment in oil and natural gas properties and equipment	(31,534)	(198,627)	—	(230,161)
Changes in operating assets and liabilities associated with investing activities	(29,806)	(25,619)	—	(55,425)
Proceeds from sales of assets and other, net	372,939	—	—	372,939
Investment in subsidiary	(1,445)	—	1,445	—
Purchases of furniture, fixtures and other	(1,278)	—	—	(1,278)
Net cash used in investing activities	<u>308,876</u>	<u>(224,246)</u>	<u>1,445</u>	<u>86,075</u>
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	263,000	—	—	263,000
Repayments of long-term debt – revolving bank credit facility	(710,000)	—	—	(710,000)
Issuance of 9.00% Term Loan	297,000	—	—	297,000
Debt issuance costs	(6,669)	—	—	(6,669)
Other	(212)	—	—	(212)
Investment from parent	—	1,445	(1,445)	—
Net cash provided by financing activities	<u>(156,881)</u>	<u>1,445</u>	<u>(1,445)</u>	<u>(156,881)</u>
Decrease in cash and cash equivalents	61,748	—	—	61,748
Cash and cash equivalents, beginning of period	23,666	—	—	23,666
Cash and cash equivalents, end of period	<u>\$ 85,414</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 85,414</u>

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

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2014
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Operating activities:				
Net income (loss)	\$ (11,661)	\$ 8,320	\$ (8,320)	\$ (11,661)
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	278,387	232,715	—	511,102
Amortization of debt issuance costs and premium	701	—	—	701
Share-based compensation	14,744	—	—	14,744
Derivative gain	(3,965)	—	—	(3,965)
Cash payments on derivative settlements	(5,318)	—	—	(5,318)
Deferred income taxes	(32,456)	27,696	—	(4,760)
Earnings of affiliates	(8,320)	—	8,320	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	19,553	9,957	—	29,510
Joint interest and other receivables	(4,255)	—	—	(4,255)
Income taxes	27,650	(24,507)	—	3,143
Prepaid expenses and other assets	45,962	(7,525)	(23,425)	15,012
Asset retirement obligations	(57,253)	(17,060)	—	(74,313)
Accounts payable, accrued liabilities and other	11,083	(30,475)	23,425	4,033
Net cash provided by operating activities	<u>274,852</u>	<u>199,121</u>	<u>—</u>	<u>473,973</u>
Investing activities:				
Acquisition of property interest in oil and natural gas properties	(17,407)	(54,827)	—	(72,234)
Investment in oil and natural gas properties and equipment	(312,044)	(242,334)	—	(554,378)
Changes in operating assets and liabilities associated with investing activities	1,733	35,717	—	37,450
Investment in subsidiary	(62,323)	—	62,323	—
Purchases of furniture, fixtures and other	(3,340)	—	—	(3,340)
Net cash used in investing activities	<u>(393,381)</u>	<u>(261,444)</u>	<u>62,323</u>	<u>(592,502)</u>
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	556,000	—	—	556,000
Repayments of long-term debt – revolving bank credit facility	(399,000)	—	—	(399,000)
Dividends to shareholders	(30,260)	—	—	(30,260)
Other	(345)	—	—	(345)
Investment from parent	—	62,323	(62,323)	—
Net cash provided in financing activities	<u>126,395</u>	<u>62,323</u>	<u>(62,323)</u>	<u>126,395</u>
Increase in cash and cash equivalents	7,866	—	—	7,866
Cash and cash equivalents, beginning of period	15,800	—	—	15,800
Cash and cash equivalents, end of period	<u>\$ 23,666</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 23,666</u>

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

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2013
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Operating activities:				
Net income	\$ 51,322	\$ 24,400	\$ (24,400)	\$ 51,322
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	250,818	200,711	—	451,529
Amortization of debt issuance costs and premium	1,645	—	—	1,645
Share-based compensation	11,525	—	—	11,525
Derivative loss	8,470	—	—	8,470
Cash payments on derivative settlements	(8,589)	—	—	(8,589)
Deferred income taxes	7,564	23,356	—	30,920
Earnings of affiliates	(24,400)	—	24,400	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	6,182	(5,202)	—	980
Joint interest and other receivables	34,257	—	—	34,257
Income taxes	54,813	(10,485)	—	44,328
Prepaid expenses and other assets	(25,329)	(18,835)	34,120	(10,044)
Asset retirement obligations	(65,438)	(16,105)	—	(81,543)
Accounts payable, accrued liabilities and other	74,693	(12,665)	(34,120)	27,908
Net cash provided by operating activities	<u>377,533</u>	<u>185,175</u>	<u>—</u>	<u>562,708</u>
Investing activities:				
Acquisition of property interest in oil and natural gas properties	—	(82,424)	—	(82,424)
Investment in oil and natural gas properties and equipment	(349,804)	(202,150)	—	(551,954)
Changes in operating assets and liabilities associated with investing activities	(14,732)	13,382	—	(1,350)
Investment in subsidiary	(86,017)	—	86,017	-
Proceeds from sales of assets and other, net	21,008	—	—	21,008
Purchases of furniture, fixtures and other	(1,435)	—	—	(1,435)
Net cash used in investing activities	<u>(430,980)</u>	<u>(271,192)</u>	<u>86,017</u>	<u>(616,155)</u>
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	563,000	—	—	563,000
Repayments of long-term debt – revolving bank credit facility	(443,000)	—	—	(443,000)
Debt issuance costs	(3,892)	—	—	(3,892)
Dividends to shareholders	(58,846)	—	—	(58,846)
Other	(260)	—	—	(260)
Investment from parent	—	86,017	(86,017)	—
Net cash used in financing activities	<u>57,002</u>	<u>86,017</u>	<u>(86,017)</u>	<u>57,002</u>
Increase in cash and cash equivalents	3,555	—	—	3,555
Cash and cash equivalents, beginning of period	12,245	—	—	12,245
Cash and cash equivalents, end of period	<u>\$ 15,800</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 15,800</u>

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

22. Supplemental Oil and Gas Disclosures—UNAUDITED

Geographic Area of Operation

All of our proved reserves are located within the United States, with a majority of those reserves located in the Gulf of Mexico and a minority located in Texas. Therefore, the following disclosures about our costs incurred, results of operations and proved reserves are on a total-company basis.

Capitalized Costs

Net capitalized costs related to our oil, NGLs and natural gas producing activities are as follows (in millions):

	December 31,		
	2015	2014	2013
Net capitalized cost:			
Proved oil and natural gas properties and equipment	\$ 7,882.3	\$ 7,924.2	\$ 7,207.1
Unproved oil and natural gas properties and equipment	20.2	121.5	132.0
Accumulated depreciation, depletion and amortization ⁽¹⁾ related to oil, NGLs and natural gas activities	(6,916.2)	(5,557.6)	(5,069.2)
Net capitalized costs related to producing activities	<u>\$ 986.3</u>	<u>\$ 2,488.1</u>	<u>\$ 2,269.9</u>

(1) Includes ceiling test write-down in 2015.

Costs Not Subject To Amortization

Costs not subject to amortization relate to unproved properties which are excluded from amortizable capital costs until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. Subject to industry conditions, evaluation of most of these properties is expected to be completed within one to five years. The following table provides a summary of costs that are not being amortized as of December 31, 2015, by the year in which the costs were incurred (in millions):

	Total	2015	2014	2013	Prior to 2013
Costs excluded by year incurred:					
Acquisition costs	\$ 13.9	\$ —	\$ 0.5	\$ 4.9	\$ 8.5
Capitalized interest not subject to amortization	4.7	1.5	1.2	0.9	1.1
Total costs not subject to amortization	<u>\$ 18.6</u>	<u>\$ 1.5</u>	<u>\$ 1.7</u>	<u>\$ 5.8</u>	<u>\$ 9.6</u>

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

Costs Incurred In Oil and Gas Property Acquisition, Exploration and Development Activities

The following costs were incurred in oil and gas acquisition, exploration, and development activities (in millions):

	Year Ended December 31,		
	2015	2014	2013
Costs incurred: (1)			
Proved properties acquisitions	\$ 15.6	\$ 111.5	\$ 96.9
Exploration (2) (3)	152.4	411.1	215.3
Development	65.5	198.7	352.9
Unproved properties acquisitions (4)	0.1	3.1	26.3
Total costs incurred in oil and gas property acquisition, exploration and development activities	<u>\$ 233.6</u>	<u>\$ 724.4</u>	<u>\$ 691.4</u>

- (1) Includes net reductions from capitalized ARO of \$0.4 million in 2015 and net additions from capitalized ARO of \$88.0 million and \$50.6 million during 2014 and 2013, respectively, associated with acquisitions, liabilities incurred, divestitures and revisions of estimates.
(2) Includes seismic costs of \$3.2 million, \$9.0 million and \$8.9 million incurred during 2015, 2014 and 2013, respectively.
(3) Includes geological and geophysical costs charged to expense of \$5.7 million, \$7.3 million and \$5.9 million during 2015, 2014 and 2013, respectively.
(4) The amounts for unproved property acquisitions include capitalized interest associated with unproved properties acquired during the period.

Depreciation, depletion, amortization and accretion expense

The following table presents our depreciation, depletion, amortization and accretion expense per barrel equivalent ("Boe") of products sold.

	Year Ended December 31,		
	2015	2014	2013
Depreciation, depletion, amortization and accretion per Boe	\$ 23.11	\$ 28.98	\$ 25.10

Oil and Natural Gas Reserve Information

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve information represent estimates only and are inherently imprecise and may be subject to substantial revisions as additional information such as reservoir performance, additional drilling, technological advancements and other factors become available. Decreases in the prices of oil, NGLs and natural gas could have an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow. We are not the operator with respect to approximately 27% of our proved developed non-producing reserves and 12% of our proved undeveloped reserves, so we may not be in a position to control the timing of all development activities.

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

The following sets forth estimated quantities of our net proved, proved developed and proved undeveloped oil, NGLs and natural gas reserves. All of the reserves are located in the United States with all located in state and federal waters in the Gulf of Mexico. The reserve estimates exclude insignificant royalties and interests owned by the Company due to the unavailability of such information. In addition to other criteria, estimated reserves are assessed for economic viability based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for the year in accordance with definitions and guidelines set forth by the SEC and the FASB. The prices used do not purport, nor should it be interpreted, to present the current market prices related to our estimated oil and natural gas reserves. Actual future prices and costs may differ materially from those used in determining our proved reserves for the periods presented. The prices used are presented in the section below entitled “Standardized Measure of Discounted Future Net Cash Flows”.

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total Energy Equivalent Reserves (1)	
				Oil Equivalent (MMBoe)	Natural Gas Equivalent (Bcfe)
Proved reserves as of Dec. 31, 2012	54.8	15.2	285.1	117.5	705.1
Revisions of previous estimates (2)	(4.3)	0.2	2.1	(3.8)	(22.8)
Extensions and discoveries (3)	13.9	2.6	22.0	20.2	121.0
Purchase of minerals in place (4)	1.5	—	4.4	2.3	13.7
Sales of reserves (5)	(0.4)	—	(0.4)	(0.5)	(3.2)
Production	(7.0)	(2.1)	(53.3)	(18.0)	(107.9)
Proved reserves as of Dec. 31, 2013	58.5	15.9	259.9	117.7	705.9
Revisions of previous estimates (6)	1.6	0.1	14.3	4.1	25.3
Extensions and discoveries (7)	7.3	0.7	10.1	9.7	58.1
Purchase of minerals in place (8)	1.5	1.2	20.7	6.1	36.5
Production	(7.2)	(2.1)	(50.1)	(17.6)	(105.8)
Proved reserves as of Dec. 31, 2014	61.7	15.8	254.9	120.0	720.0
Revisions of previous estimates (9)	4.8	(0.9)	4.9	4.7	28.0
Revisions related to sold properties (10)	(12.1)	(4.8)	(2.9)	(17.4)	(104.3)
Extensions and discoveries (11)	2.4	0.2	8.8	4.1	24.4
Purchase of minerals in place (12)	—	—	6.1	1.0	6.1
Sales of reserves (13)	(13.5)	(2.1)	(20.2)	(19.0)	(113.8)
Production	(7.8)	(1.6)	(46.2)	(17.0)	(102.3)
Proved reserves as of Dec. 31, 2015	<u>35.5</u>	<u>6.6</u>	<u>205.4</u>	<u>76.4</u>	<u>458.1</u>
Year-end proved developed reserves:					
2015	29.4	6.4	198.5	69.0	413.5
2014	35.7	10.7	221.1	83.3	499.7
2013	36.2	11.1	232.7	86.1	516.1
Year-end proved undeveloped reserves:					
2015 (14)	6.1	0.2	6.9	7.4	44.6
2014	26.0	5.1	33.8	36.7	220.3
2013	22.3	4.8	27.2	31.6	189.8

Volume measurements:

Bbl – barrel

MMBbls – million barrels for crude oil, condensate or NGLs

MMBoe – million barrels of oil equivalent

Mcf – thousand cubic feet

Bcf – billion cubic feet

Bcfe – billion cubic feet of gas equivalent

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

- (1) The conversion to barrels of oil equivalent and cubic feet equivalent were determined using the energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs (totals may not compute due to rounding). The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for crude oil, NGLs and natural gas may differ significantly.
- (2) Includes upward revision due to price of 1.9 MMBoe; negative revisions of 4.9 MMBoe at our Yellow Rose field for performance and technical changes, 2.3 MMBoe at our High Island 21/22 field for performance, 1.3 MMBoe at our Ship Shoal 349/359 field for performance; and positive performance revisions of 0.7 MMBoe at our Main Pass 98 field, 0.7 MMBoe at our South Timbalier 314, 0.6 MMBoe at our Main Pass 108 field and 0.5 MMBoe our South Timbalier 176 field.
- (3) Includes extensions and discoveries of 12.6 MMBoe at our Yellow Rose field, 4.2 MMBoe at our Ship Shoal 349 field and 1.9 MMBoe at our Mississippi Canyon 698 field.
- (4) Primarily due to the acquisition of the Callon Properties.
- (5) Primarily due to the sales of our non-working interests in the Green Canyon 60 field, the Green Canyon 19 field and the West Delta area block 29.
- (6) Includes upwards revisions due to price of 0.3 MMBoe; positive revisions of 2.4 MMBoe at our Fairway Field, 1.2 MMBoe at our Mississippi Canyon 800 field and 6.4 MMBoe at various fields; and negative revisions of 3.9 MMBoe at our Yellow Rose field and 2.4 MMBoe at various other fields.
- (7) Includes extensions and discoveries of 4.1 MMBoe at our Yellow Rose field and 4.1 MMBoe at our Mississippi Canyon 782 field.
- (8) Primarily due to acquiring additional ownership in the Fairway Field and acquisition of the Woodside Properties.
- (9) Includes upwards revisions of 7.4 MMBoe at the Ship Shoal 349 field (Mahogany), 1.9 MMBoe at our Brazo A-133 field, 1.3 MMBoe at our Atwater 575 field, 1.3 MMBoe at our Mississippi Canyon 243 field (Matterhorn), 1.1 MMBoe at our Fairway Field, partially offset by downward revisions due to price of 10.7 MMBoe. The revision for price excludes the Yellow Rose field sold during 2015.
- (10) Revisions related to the Yellow Rose field during 2015, which were primarily due to price reductions, up to the date of the sale in October 2015.
- (11) Primarily due to increases at Ewing Bank 910.
- (12) Primarily due to purchase of additional interest at Brazos A-133.
- (13) Related primarily to the sale of the Yellow Rose field in October 2015, which had estimated reserves at the date of sale of 19.0 MMBoe.
- (14) We believe that we will be able to develop all but 1.2 MMBoe of the reserves classified as proved undeveloped (“PUDs”), or approximately 16%, out of the total of 7.4 MMBoe classified as PUDs at December 31, 2015, within five years from the date such reserves were initially recorded. The exception is at the Mississippi Canyon 243 field (Matterhorn) where the field is being developed using a single floating tension leg platform requiring an extended sequential development plan. The platform cannot support a rig that would allow additional wells to be drilled, but can support a rig to allow sidetracking of wells. A portion of the PUDs in this field were originally recorded in our reserves as of December 31, 2010. The development of these PUDs will be delayed until an existing well is depleted and available to sidetrack. Based on the latest reserve report, a well is expected to be drilled to develop the Mississippi Canyon 243 field (Matterhorn) PUDs in 2020.

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

Standardized Measure of Discounted Future Net Cash Flows

The following presents the standardized measure of discounted future net cash flows related to our proved oil and natural gas reserves together with changes therein. Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the unweighted average of first-day-of-the-month commodity prices for the periods presented. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials. Due to the lack of a benchmark price for NGLs, a ratio is computed for each field of the NGLs realized price compared to the crude oil realized price. Then, this ratio is applied to the crude oil price using FASB/SEC guidance. The average commodity prices weighted by field production and after adjustments related to the proved reserves are as follows:

	December 31,			
	2015	2014	2013	2012
Oil - per barrel	\$ 46.94	\$ 91.12	\$ 99.65	\$ 98.13
NGLs per barrel	17.60	34.63	35.21	47.30
Natural gas per Mcf	2.50	4.27	3.80	2.77

Future production, development costs and ARO are based on costs in effect at the end of each of the respective years with no escalations. Estimated future net cash flows, net of future income taxes, have been discounted to their present values based on a 10% annual discount rate.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of our oil and natural gas reserves. These estimates reflect proved reserves only and ignore, among other things, future changes in prices and costs, revenues that could result from probable reserves which could become proved reserves in 2016 or later years and the risks inherent in reserve estimates. The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is as follows (in millions):

	Year Ended December 31,		
	2015	2014	2013
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	\$ 2,296.7	\$ 7,258.5	\$ 7,376.7
Future costs:			
Production	(840.1)	(2,224.5)	(2,142.8)
Development	(161.4)	(922.0)	(1,001.4)
Dismantlement and abandonment	(471.8)	(475.4)	(441.6)
Income taxes (1)	—	(948.4)	(986.9)
Future net cash inflows before 10% discount	823.4	2,688.2	2,804.0
10% annual discount factor	(209.5)	(985.4)	(1,129.4)
Total	<u>\$ 613.9</u>	<u>\$ 1,702.8</u>	<u>\$ 1,674.6</u>

- (1) No future income taxes were estimated to be paid in 2015 as our present tax position has sufficient tax basis and net operating loss carrying forwards to offset any future taxes. State income taxes were disregarded due to immateriality.

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

	Year Ended December 31,		
	2015	2014	2013
Changes in Standardized Measure			
Standardized measure, beginning of year	\$ 1,702.8	\$ 1,674.6	\$ 1,846.4
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(289.1)	(650.9)	(686.1)
Net changes in price, net of future production costs	(1,455.6)	(278.6)	(65.2)
Extensions and discoveries, net of future production and development costs	65.3	309.6	393.8
Changes in estimated future development costs	(8.5)	(56.4)	(91.1)
Previously estimated development costs incurred	158.9	263.1	262.1
Revisions of quantity estimates	137.9	118.6	(91.6)
Accretion of discount	150.6	180.6	202.2
Net change in income taxes	600.8	(11.4)	56.6
Purchases of reserves in-place	6.0	86.7	79.6
Sales of reserves in-place	(401.4)	—	(53.1)
Changes in production rates due to timing and other	(53.8)	66.9	(179.0)
Net increase (decrease) in standardized measure	(1,088.9)	28.2	(171.8)
Standardized measure, end of year	<u>\$ 613.9</u>	<u>\$ 1,702.8</u>	<u>\$ 1,674.6</u>

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that any 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 December 31, 2015 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission'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.

Management's Annual Report on Internal Control Over Financial Reporting

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2015, is set forth in "Management's Report on Internal Control over Financial Reporting" included under Part II, Item 8 in this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2015, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included under Part II, Item 8 in this Form 10-K.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K and to the information set forth following Item 3 of this report.

Item 11. *Executive Compensation*

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 14. *Principal Accountant Fees and Services*

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as a part of this report:

1. Financial Statements. See "Index to Consolidated Financial Statements" in Part II, Item 8 of this Form 10-K.

All schedules are omitted because they are not applicable, not required or the required information is included in the consolidated financial statements or related notes.

2. Exhibits:

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of October 17, 2013, by and among Callon Petroleum Operating Company, as Seller, and W&T Offshore, Inc., as Buyer (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed November 7, 2013 (File No. 001-32414))
2.2	Purchase and Sale Agreement, dated as of August 31, 2015, by and among Ajax Resources, LLC, as Buyer, and W&T Offshore, Inc., as Seller (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed October 21, 2015 (File No. 001-32414))
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed February 24, 2006 (File No. 001-32414))
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
3.3	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q, filed July 31, 2012 (File No. 001-32414))
4.1	Specimen Common Stock Certificate. (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
4.2	Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))
4.3	First Supplemental Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))
4.4	Form of 8.50% Senior Notes due 2019. (Incorporated by reference to Exhibit 4.3 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))
10.1*	2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.11 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.2*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Stephen L. Schroeder, dated July 5, 2006. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed July 12, 2006 (File No. 001-32414))

Exhibit Number	Description
10.3*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed February 26, 2007 (File No. 001-32414))
10.4*	Indemnification and Hold Harmless Agreement, dated September 24, 2008, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K, filed September 26, 2008 (File No. 001-32414))
10.5*	W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan. (Incorporated by reference from Appendix A to the Company's Definitive Proxy Statement on Schedule 14A, filed April 2, 2010 (File No. 001-32414))
10.6*	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)
10.7*	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)
10.8*	Form of Employment Agreement for Executive Officers other than the Chief Executive Officer. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 6, 2010 (File No. 001-32414))
10.9*	Employment Agreement between W&T Offshore, Inc. and Tracy W. Krohn dated as of November 1, 2010. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on November 5, 2010 (File No. 001-32414))
10.10*	Form of Indemnification and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors. (Incorporated by reference to Exhibit 10.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 001-32414))
10.11*	Form of Employment Agreement by and between W&T Offshore, Inc. and Thomas P. Murphy. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed August 6, 2010 (File No. 001-32414))
10.12*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Thomas P. Murphy, dated as of June 19, 2012. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed June 22, 2012 (File No. 001-32414))
10.13*	Tracy W. Krohn Executive Annual Incentive Award Agreement for Fiscal 2013. (Incorporated by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q, filed August 8, 2013 (File No. 001-32414))
10.14	Fifth Amended and Restated Credit Agreement, dated as of November 8, 2013, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed November 13, 2013 (File No. 001-32414))
10.15*	Form of Executive Annual Incentive Agreement for Fiscal 2014. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q, filed May 8, 2014 (File No. 001-32414))

Exhibit Number	Description
10.16*	Form of 2014 Executive Restricted Stock Unit Agreement. (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q, filed May 8, 2014 (File No. 001-32414))
10.17*	Tracy W. Krohn Executive Annual Incentive Agreement for Fiscal 2014. (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q, filed May 8, 2014 (File No. 001-32414))
10.18	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 23, 2015, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent, and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed April 27, 2015 (File No. 001-32414))
10.19	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of May 8, 2015, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 14, 2015 (File No. 001-32414))
10.20	\$300,000,000 Term Loan Agreement, dated May 11, 2015, by and among W&T Offshore, Inc., Morgan Stanley Senior Funding, Inc., as administrative agent and collateral trustee, and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed May 14, 2015 (File No. 001-32414))
10.21	Intercreditor Agreement, dated May 11, 2015, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as priority lien agent, Morgan Stanley Senior Funding, Inc., as second lien collateral trustee, and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed May 14, 2015 (File No. 001-32414))
10.21	Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of October 30, 2015, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed November 5, 2015 (File No. 001-32414))
10.22*	Form of Executive Annual Incentive Agreement for Fiscal 2015. (Incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q, filed November 6, 2015 (File No. 001-32414))
10.23* **	Form of 2015 Executive Restricted Stock Unit Agreement.
12.1**	Ratio of Earnings to Fixed Charges
14.1	W&T Offshore, Inc. Code of Business Conduct and Ethics (as amended). (Incorporated by reference to Exhibit 14.1 of the Company's Current Report on Form 8-K, filed November 17, 2005)
21.1**	Subsidiaries of the Registrant.
23.1**	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
23.2**	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
31.1**	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2**	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer of W&T Offshore, Inc. pursuant to 18 U.S.C. § 1350.

Exhibit Number	Description
99.1**	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
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.

* Management Contract or Compensatory Plan or Arrangement.

** Filed or furnished herewith.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry that are used in this report.

Acquisitions. Refers to acquisitions, mergers or exercise of preferential rights of purchase.

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using an energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

Boe. Barrel of oil equivalent.

Boe/d. Barrel of oil equivalent per day.

BOEM. Bureau of Ocean Energy Management. The agency is responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

BOEMRE. Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service), was the federal agency that manages the nation's natural gas, oil and other mineral resources on the outer continental shelf. The BOEMRE was split into three separate entities: the Office of Natural Resources Revenue; the Bureau of Ocean Energy Management; and the Bureau of Safety and Environmental Enforcement.

BSEE. Bureau of Safety and Environmental Enforcement. The agency is responsible for enforcement of safety and environmental regulations. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

Conventional shelf well. A well drilled in water depths less than 500 feet.

Deep shelf well. A well drilled on the outer continental shelf to subsurface depths greater than 15,000 feet and water depths of less than 500 feet.

Deepwater. Water depths greater than 500 feet in the Gulf of Mexico.

Deterministic estimate. Refers to a method of estimation whereby a single value for each parameter in the reserves calculation is used in the reserves estimation procedure.

Developed reserves. Oil and natural gas reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development project. A project by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. Refers to a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

Extension well. A well drilled to extend the limits of a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil or other hydrocarbon.

Mcfe/d. One thousand cubic feet equivalent per day.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using an energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids. These are created during the processing of natural gas.

Non-productive well. A well that is found not to have economically producible hydrocarbons.

Oil. Crude oil and condensate.

OCS. Outer continental shelf

OCS block. A unit of defined area for purposes of management of offshore petroleum exploration and production by the BOEM.

ONRR. Office of Natural Resources Revenue. The agency assumed the functions of the former Minerals Revenue Management Program, which had been renamed to the Bureau of Ocean Energy Management, Regulation and Enforcement.

Probabilistic estimate. Refers to a method of estimation whereby the full range of values that could reasonably occur for each unknown parameter in the reserves estimation procedure is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Productive well. A well that is found to have economically producible hydrocarbons.

Proved properties. Properties with proved reserves.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in

this definition, “existing economic conditions” include prices and costs at which economic production from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(22) of Regulation S-X.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

PV-10 value. A term used in the industry that is not a defined term in generally accepted accounting principles. We define PV-10 as the present value of estimated future net revenues of estimated proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs. PV-10 excludes cash flows for asset retirement obligations, general and administrative expenses, derivatives, debt service and income taxes.

Reasonable certainty. When deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities of hydrocarbons will be recovered. When probabilistic methods are used, reasonable certainty means at least a 90% probability that the quantities of hydrocarbons actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience, engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

Recompletion. The completion for production of an existing well bore in another formation from that which the well has been previously completed.

Reliable technology. A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Estimated remaining quantities of oil, natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering the oil, natural gas or related substances to market, and all permits and financing required to implement the project.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Supra-salt. A geological layer lying above the salt layer.

Undeveloped reserves. Oil and natural gas reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic production at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties. Properties with no proved reserves.

**W&T OFFSHORE, INC.
AMENDED AND RESTATED INCENTIVE COMPENSATION PLAN**

2015 EXECUTIVE RESTRICTED STOCK UNIT AGREEMENT

This Agreement is made and entered into as of _____, 2015 (the "**Date of Grant**"), by and between W&T Offshore, Inc., a Texas corporation (the "**Company**") and the executive whose name appears in the footer below ("**you**");

WHEREAS, the Company in order to induce you to enter into and to continue and dedicate service to the Company and to materially contribute to the success of the Company agrees to grant you this restricted stock unit award;

WHEREAS, the Company adopted the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, as it may be amended from time to time (the "**Plan**") under which the Company is authorized to grant stock-based awards to certain employees and service providers of the Company;

WHEREAS, a copy of the Plan has been furnished to you and shall be deemed a part of this restricted stock unit award agreement ("**Agreement**") as if fully set forth herein and the terms capitalized but not defined herein shall have the meanings set forth in the Plan;

WHEREAS, the Company adopted the W&T Offshore, Inc. Stock Ownership and Retention Policy, as it may be amended from time to time (the "**Policy**") under which the Company has established various stock ownership and retention requirements;

WHEREAS, a copy of the Policy has been furnished to you and, as this Award (as defined below) shall be subject to the terms and conditions of the Policy, shall be deemed a part of this Agreement as if fully set forth herein; and

WHEREAS, you desire to accept the restricted stock unit award made pursuant to this Agreement.

NOW, THEREFORE, in consideration of and mutual covenants set forth herein and for other valuable consideration hereinafter set forth, the parties agree as follows:

1. **The Grant.** Subject to the conditions set forth below and the adjustment provisions of Section 3(b), the Company hereby grants to you effective as of the Date of Grant, as a matter of separate inducement but not in lieu of any salary or other compensation for your services for the Company, an award (the "**Award**") consisting of _____ shares of restricted stock units in accordance with the terms and conditions set forth herein and in the Plan (the "**Restricted Stock Units**"), along with any additional rights related to the Restricted Stock Units as described in Section 2 of this Agreement. To the extent you commenced full time employment after the beginning of the initial performance period, the total number of Restricted Stock Units recited above has been adjusted to reflect that fact.

2. **Dividend Equivalents.** As of the Date of Grant above, this grant of Restricted Stock Units also includes a tandem grant of Dividend Equivalents with respect to each share of

Executive (2015):

Restricted Stock Units granted to you pursuant to Section 1 of this Agreement; *provided, however*, that you shall not receive Dividend Equivalents for any distributions made with respect to a share of Stock prior to the satisfaction of the Performance Vesting Requirement (as defined below). In the event that the Performance Vesting Requirement is satisfied prior to the Vesting Date, you shall receive Dividend Equivalents for any distributions made with respect to a share of Stock for the period of time between the day the attainment of the Performance Vesting Requirement occurs and the Vesting Date, taking into account that an adjustment shall be made to the number of Dividend Equivalents granted to you to reflect any adjustments made to your Restricted Stock Units pursuant to Section 3(b) below. All Dividend Equivalents granted on and after the Date of Grant shall carry identical vesting restrictions as shall be attached to the Restricted Stock Units giving rise to such Dividend Equivalents, thus, if the Performance Vesting Requirement is not satisfied, all rights to Dividend Equivalents shall immediately cease. If a Restricted Stock Unit is forfeited, your tandem Dividend Equivalents with respect to such Restricted Stock Units shall automatically terminate at that time. Any Dividend Equivalents payment will be made on or promptly following the date on which the dividends are otherwise paid to the holders of Stock; *provided, however*, in no event shall the dividend payment be made later than 30 days following the date on which the Company pays such dividend to the holders of Stock.

3. Vesting Date, Adjustment, and Other Restrictions. Subject to the terms and conditions of this Agreement and the Plan, the forfeiture restrictions on the Restricted Stock Units will lapse and the Restricted Stock Units will vest, subject to the Performance Vesting Requirement, on December 15th of the second calendar year following the calendar year in which the Date of Grant occurs (the “**Vesting Date**”).

(a) Performance Vesting Requirement. The “**Performance Vesting Requirement**” means the achievement of the “**Performance Goals**,” which are performance criteria established by the Committee pursuant to Section 8 of the Plan and set forth in Appendix A attached hereto.

(b) Adjustments Following the Satisfaction of the Performance Vesting Requirement. Immediately following the Committee’s certification of the satisfaction of the applicable Performance Vesting Requirement and the applicable level of achievement attained in connection therewith, the number of Restricted Stock Units subject to a Performance Vesting Requirement granted to you pursuant to Section 1 of this Agreement shall be adjusted to reflect the achievement of the Performance Goals during the applicable performance period. To the extent after the Date of the Grant you were on unpaid leave and/or were not actively employed during any part of the applicable performance period, your Restricted Stock Units subject to that Performance Vesting Requirement shall be further adjusted to equal the number of Restricted Stock Units equal to (x) your number of Restricted Stock Units subject to that Performance Vesting Requirement adjusted above to reflect the achievement of the Performance Goals times (y) a number equal to the quotient resulting from your Actual Base Salary (as hereinafter defined) divided by your Base Salary (as hereinafter defined). In addition, the Committee has the right to further reduce or eliminate the number of Restricted Stock Units granted to you for any reason regardless of the satisfaction of the Performance Vesting Requirement and the applicable level of achievement attained in connection therewith. In the event of a negative adjustment, the remaining Restricted Stock Units subject to that Performance Vesting

Requirement granted to you pursuant to Section 1 of this Agreement not eligible for vesting shall be forfeited as of the end of the applicable performance period. The Committee shall promptly notify you of any and all adjustments made to your Restricted Stock Units pursuant to this Section 3(b).

For purposes of this Agreement, “**Base Salary**” means your annual pay rate in effect at the beginning of the applicable performance period calculated over the applicable performance period, (i) including any amounts deferred pursuant to an election under any 401(k) plan, pre-tax premium plan, deferred compensation plan, or flexible spending account sponsored by the Company or any Subsidiary, but (ii) *excluding* any incentive compensation, employee benefit, or other cash benefit paid or provided under any incentive, bonus or employee benefit plan sponsored by the Company or any Subsidiary, and/or any excellence award, gains upon stock option exercises, restricted stock grants or vesting, moving or travel expense reimbursement, imputed income, or tax gross-ups, without regard to whether the payment or gain is taxable income to you. To the extent you commence employment after the beginning of the initial performance period, your Base Salary for that initial performance period shall mean the base salary you would receive working full time (based on your annual pay rate in effect on your first day of employment) for the period from your first day of employment until the end of the initial performance period.

For purposes of this Agreement, “**Actual Base Salary**” means the base salary you actually received during the applicable performance period calculated as of the last day of the applicable performance period, (i) including any amounts deferred pursuant to an election under any 401(k) plan, pre-tax premium plan, deferred compensation plan, or flexible spending account sponsored by the Company or any Subsidiary, and any overtime paid to you as an offshore employee required by your standard work schedule, but (ii) *excluding* any incentive compensation, employee benefit, or other benefit paid or provided under any incentive, bonus or employee benefit plan sponsored by the Company or any Subsidiary, all overtime paid other than as specified in (i) above and/or any excellence award, gains upon stock option exercises, restricted stock grants or vesting, moving or travel expense reimbursement, sign on bonus, imputed income, or tax gross-ups, without regard to whether the payment or gain is taxable income to you.

By way of example only, the Performance Vesting Requirement adjustment described above will operate as follows: if you are granted 1,000 Restricted Stock Units subject to a Performance Vesting Requirement on the Date of Grant, and the level of achievement of the Performance Goals during the applicable performance period is reached at a level the Company has designated as a 75% achievement level, it will only be possible for you to vest in 750 Restricted Stock Units on the Vesting Date and the remaining 250 Restricted Stock Units shall be forfeited as of the end of the performance period. In addition, to the extent you were on unpaid leave and/or were not actively employed during any part of the applicable performance period, the number of such Restricted Stock Units shall be further adjusted as described in the first paragraph of Section 3(b) to the extent your Actual Base Salary for the applicable performance period is less than your Base Salary for such performance period. As noted in the first paragraph of Section 3(b), the Committee has the right to further reduce or eliminate the number of Restricted Stock Units granted to you for any reason regardless of the satisfaction of the Performance Vesting Requirement and the applicable level of achievement attained in

connection therewith. Following the satisfaction of the Performance Vesting Requirement and the adjustments herein provided but prior to the Vesting Date, you will be then eligible to receive Dividend Equivalents with respect to the adjusted Restricted Stock Units rather than the original 1,000 Restricted Stock Units. Upon the applicable settlement date of your Restricted Stock Units, you will receive a settlement from the Company with respect to such adjusted Restricted Stock Units rather than the original 1,000 Restricted Stock Units.

(c) Other Restrictions. Subject to Section 6 of this Agreement, the restrictions on your Restricted Stock Units will expire on the Vesting Date only if you have been an employee or service provider of the Company or of a Subsidiary continuously from the Date of Grant through the Vesting Date. Other than as provided in Section 6(d)(i) below, in the event that the Performance Vesting Requirement is not satisfied, no portion of the Restricted Stock Units subject to that Performance Vesting Requirement shall become vested. Restricted Stock Units that have become vested pursuant to this Section 3 shall be referred to herein as the “*Vested Units*.”

4. Settlement.

(a) Form of Settlement. The Committee, in its sole discretion, shall determine at the time of such settlement whether the Vested Units will be settled: (i) in a single lump sum cash payment in an amount equal to the Fair Market Value of Stock as of the date of settlement multiplied by the number of Vested Units to be settled, (ii) in shares of such Stock, or (iii) in a combination of cash and shares of Stock. Settlement of Vested Units shall be subject to and pursuant to rules and procedures established by the Committee in its sole discretion.

(b) Time of Settlement. The Vested Units shall be settled by the Company as soon as administratively feasible following the Vesting Date, but in no event shall such settlement occur later than 75 days following the Vesting Date. In the event the Restricted Stock Units become Vested Units pursuant to Section 6 below, the Company will settle the Vested Units as soon as administratively practicable following the time of vesting noted in Section 6 below, but in no event shall such settlement occur later than 75 days following the applicable vesting event.

5. Restrictions, Forfeiture and Limitations on Ownership. The shares of Restricted Stock Units are restricted in the sense that they may be forfeited to the Company prior to the time the Restricted Stock Units are deemed Vested Units. You, or your executor, administrator, heirs, or legatees shall have the right to vote any shares of Stock you may receive as settlement of the Vested Units and hold all other privileges of a shareholder of the Company only from the date of issuance of a Stock certificate in your name representing payment of a Vested Unit in the form of a share of Stock, or the delivery of the Stock to the Company’s transfer agent, as applicable.

6. Termination of Services or Change in Control.

(a) Termination due to your Death or Disability. Following the satisfaction of the Performance Vesting Requirement, if your employment or service relationship with the Company and any of its Subsidiaries is terminated as a result of your death or Disability (as defined below), then the forfeiture restrictions on your Restricted Stock Units subject to that

Performance Vesting Requirement, subject to any adjustment pursuant to Section 3(b) above, shall automatically lapse as to the outstanding unvested shares of Restricted Stock Units subject to that Performance Vesting Requirement, and in the case of your Disability, subject to Section 12 of this Agreement. If your employment or service relationship with the Company and any of its Subsidiaries is terminated as a result of your death or Disability prior to the satisfaction of the Performance Vesting Requirement, no portion of the Restricted Stock Units subject to that Performance Vesting Requirement will become Vested Units.

For purposes of this Section 6(a), the term “**Disability**” shall have the meaning given such term in any written employment, severance or other similar individual agreement (an “**Individual Agreement**”) between you and the Company. In the event that there is no existing written Individual Agreement between you and the Company or if any such agreement does not define Disability, the term “**Disability**” shall mean: (i) a physical or mental impairment of sufficient severity that, in the opinion of the Company, (A) you are unable to continue performing the duties assigned to you prior to such impairment or (B) your condition entitles you to disability benefits under any insurance or employee benefit plan of the Company or its Subsidiaries, and (ii) the impairment or condition is cited by the Company as the reason for your termination; *provided, however*, that in all cases, the term Disability shall be applied and interpreted in compliance with section 409A of the Code and the regulations thereunder.

(b) Termination due to your Normal Retirement. Following the satisfaction of the Performance Vesting Requirement, if your employment or service relationship with the Company and any of its Subsidiaries is terminated as a result of your Normal Retirement prior to the Vesting Date, then the restrictions on a number of the shares of your Restricted Stock Units subject to that Performance Vesting Requirement, subject to any adjustment pursuant to Section 3(b) above, shall automatically lapse pro-rata in relation to the amount of time you have been employed by, or in the service of, the Company or any of its Subsidiaries, as described below; *provided, however*, that such restrictions shall lapse subject to the additional provisions of Section 12 of this Agreement, if applicable. Solely for purposes of determining the number of shares which may lapse or vest pursuant to this Section 6(b), the Restricted Stock Units subject to that Performance Vesting Requirement, as adjusted pursuant to Section 3(b) above, shall be referred to in two portions, two-thirds (2/3) of the Restricted Stock Units shall be the “**Two-Year Portion**”; the remaining and final one-third (1/3) of the Restricted Stock Units shall be the “**Three-Year Portion**.” Following a termination of your employment or service due to your Normal Retirement:

(i) restrictions will lapse on a number of Restricted Stock Units in the Two-Year Portion equal to the product of (A) two-thirds (2/3) of the total number of Restricted Stock Units granted to you, subject to any adjustment pursuant to Section 3(b) above, times (B) a fraction, the numerator of which is the number of full months (counting the month in which your termination of employment occurs as a full month), beginning with the first day of the first month of the year in which the Date of Grant occurs, during which you were employed by the Company and/or any Subsidiary and the denominator of which is 24; plus

(ii) restrictions will lapse on a number of Restricted Stock Units in the Three-Year Portion equal to the product of (A) one-third (1/3) of the total number of Restricted Stock Units granted to you, subject to any adjustment pursuant to Section 3(b) above, times (B) a

fraction, the numerator of which is the number of full months (counting the month in which your termination of employment occurs as a full month), beginning with the first day of the first month of the year in which the Date of Grant occurs, during which you were employed by the Company and/or any Subsidiary and the denominator of which is 36.

If your employment or service relationship with the Company and any of its Subsidiaries is terminated as a result of your Normal Retirement prior to the satisfaction of the Performance Vesting Requirement, no portion of the Restricted Stock Units subject to that Performance Vesting Requirement will become Vested Units. For purposes of this Section 6(b), the term “*Normal Retirement*” shall have the meaning given such term in any Individual Agreement between you and the Company. In the event that there is no existing written Individual Agreement between you and the Company or if any such agreement does not define Normal Retirement, the term “*Normal Retirement*” shall mean the termination of your employment or service relationship with the Company and each of its Subsidiaries by which you are employed or provide services to due to your voluntary retirement on or after the date that you attain age 67.

(c) Termination for Any Other Reason. Subject to Sections 6(d) and 6(e) below, if your employment or service relationship with the Company or any of its Subsidiaries is terminated for any other reason other than your death, Disability or your Normal Retirement prior to the Vesting Date, then that portion, if any, of the Restricted Stock Units granted pursuant to this Agreement for which have not become Vested Units as of the date of termination shall become null and void as of the date of such termination; *provided, however*, that, subject to the Performance Vesting Requirement, the portion, if any, of your Vested Units as of the date of such termination will survive the termination of employment.

(d) Change in Control.

(i) Prior to Satisfaction of the Performance Vesting Requirement. Notwithstanding anything to the contrary in Section 3 or the remainder of this Section 6, in the event that a Change in Control is consummated prior to both the Vesting Date and the end of the applicable performance period for which the Performance Vesting Requirement relates, forfeiture restrictions on all Restricted Stock Units subject to that Performance Vesting Requirement granted to you pursuant to Section 1 of this Agreement shall automatically lapse and the Restricted Stock Units subject to that Performance Vesting Requirement will vest, subject further to Section 12 of this Agreement.

(ii) Following the Satisfaction of the Performance Vesting Requirement. Notwithstanding anything to the contrary in the remainder of this Section 6, in the event that a Change in Control is consummated prior to the Vesting Date but following the satisfaction of the Performance Vesting Requirement, forfeiture restrictions on your Restricted Stock Units subject to that Performance Vesting Requirement, subject to any adjustment pursuant to Section 3(b) above, shall automatically lapse and such Restricted Stock Units subject to that Performance Vesting Requirement will vest subject further to Section 12 of this Agreement. For further clarity, in the event that the Change in Control is consummated following the applicable performance period to which the Performance Vesting Requirement relates, but the Performance Vesting Requirement was not achieved during such time, no portion

of the Restricted Stock Units subject to that Performance Vesting Requirement shall become Vested Units upon a Change in Control.

(iii) Other restrictions. Nothing within this Section 6(d) is intended to modify Sections 6(a) or 6(b) above regarding the full acceleration or pro-rata acceleration, as applicable, of your Restricted Stock Units upon a termination of employment due to death, Disability or Normal Retirement. The provisions of Sections 6(a) and 6(b) shall apply to a termination of your employment or service for death, Disability or Normal Retirement, as applicable, whether or not such a termination of employment or service were to occur in connection with a Change in Control.

(e) Effect of Individual Agreement. Notwithstanding any provision herein to the contrary, in the event of any inconsistency between this Section 6 and any Individual Agreement entered into by and between you and the Company, the terms of such an Individual Agreement shall control.

7. Leave of Absence. With respect to the Award, the Company may, in its sole discretion, determine that if you are on leave of absence for any reason you will be considered to still be in the employ of, or providing services for, the Company, provided that rights to the Restricted Stock Units during a leave of absence will be limited to the extent to which those rights were earned or vested when the leave of absence began.

8. Delivery of Stock. In the event the Committee determines to settle the Restricted Stock Units in the form of Stock, promptly following the expiration of the restrictions on the Restricted Stock Units as contemplated in Sections 3 or 6 of this Agreement, the Company shall either cause to be issued and delivered to you or your designee a certificate or other evidence of the number of Restricted Stock Units as to which restrictions have lapsed, free of any restrictive legend relating to the lapsed restrictions, or cause those number of Restricted Stock Units to be properly registered with the Company's transfer agent as appropriate, upon receipt by the Company of any tax withholding as may be requested pursuant to Section 9 of this Agreement. The value of such Restricted Stock Units shall not bear any interest owing to the passage of time.

9. Payment of Taxes. The Company may require you to pay to the Company (or the Company's Subsidiary if you are an employee of a Subsidiary of the Company), an amount the Company deems necessary to satisfy its (or its Subsidiary's) current or future obligation to withhold federal, state or local income or other taxes that you incur as a result of the Award. With respect to any such required tax withholding, the Company will withhold from the cash payment or the shares of Stock to be issued to you under this Agreement, as applicable, the cash amount or the number of shares necessary to satisfy the Company's obligation to withhold taxes; where the Restricted Stock Units will be settled in shares of Stock, such a determination will be based on the shares' Fair Market Value at the time such determination is made. In the event the Restricted Stock Units are settled in shares of Stock, and Company determines that the aggregate Fair Market Value of the shares of Stock withheld as payment of any tax withholding obligation is insufficient to discharge that tax withholding obligation, then you must pay to the Company, in cash, the amount of that deficiency immediately upon the Company's request.

10. Compliance with Securities Law. Notwithstanding any provision of this Agreement to the contrary, in the event the Restricted Stock Units are settled in shares of Stock, the issuance of Stock will be subject to compliance with all applicable requirements of federal, state, or foreign law with respect to such securities and with the requirements of any stock exchange or market system upon which the Stock may then be listed. No Stock will be issued hereunder if such issuance would constitute a violation of any applicable federal, state, or foreign securities laws or other law or regulations or the requirements of any stock exchange or market system upon which the Stock may then be listed. In addition, Stock will not be issued hereunder unless (a) a registration statement under the Securities Act of 1933, as amended (the “*Act*”), is at the time of issuance in effect with respect to the shares issued or (b) in the opinion of legal counsel to the Company, the shares issued may be issued in accordance with the terms of an applicable exemption from the registration requirements of the Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company’s legal counsel to be necessary to the lawful issuance and sale of any shares subject to the Award will relieve the Company of any liability in respect of the failure to issue such shares as to which such requisite authority has not been obtained. As a condition to any issuance hereunder, the Company may require you to satisfy any qualifications that may be necessary or appropriate to evidence compliance with any applicable law or regulation and to make any representation or warranty with respect to such compliance as may be requested by the Company. From time to time, the Board and appropriate officers of the Company are authorized to take the actions necessary and appropriate to file required documents with governmental authorities, stock exchanges, and other appropriate Persons to make shares of Stock available for issuance.

11. Right of the Company and Subsidiaries to Terminate Employment or Services. Nothing in this Agreement confers upon you the right to continue in the employ of or performing services for the Company or any Subsidiary, or interfere in any way with the rights of the Company or any Subsidiary to terminate your employment or service relationship at any time, with or without cause.

12. Non-Compete Agreements. The Company, in its sole discretion, may require you to execute a separate non-compete, non-solicitation, or similar agreement in connection with the grant of the Restricted Stock Units pursuant to this Agreement or in connection with the acceleration of the Restricted Stock Units in accordance with the provisions of Section 6 of this Agreement.

13. Furnish Information. You agree to furnish to the Company all information requested by the Company to enable it to comply with any reporting or other requirements imposed upon the Company by or under any applicable statute or regulation.

14. Remedies. The parties to this Agreement shall be entitled to recover from each other reasonable attorneys’ fees incurred in connection with the successful enforcement of the terms and provisions of this Agreement whether by an action to enforce specific performance or for damages for its breach or otherwise.

15. No Liability for Good Faith Determinations. The Company, the Committee and the members of the Board shall not be liable for any act, omission or determination taken or

made in good faith with respect to this Agreement or the Restricted Stock Units granted hereunder.

16. Execution of Receipts and Releases. Any payment of cash or any issuance or transfer of shares of Stock or other property to you, or to your legal representative, heir, legatee or distributee, in accordance with the provisions hereof, shall, to the extent thereof, be in full satisfaction of all claims of such Persons hereunder. The Company may require you or your legal representative, heir, legatee or distributee, as a condition precedent to such payment or issuance, to execute a release and receipt therefor in such form as the Company shall determine.

17. No Guarantee of Interests. The Company, the members of the Committee and the Board do not guarantee the Stock of the Company from loss or depreciation.

18. Notice. All notices required or permitted under this Agreement must be in writing and personally delivered or sent by mail and shall be deemed to be delivered on the date on which it is actually received by the person to whom it is properly addressed or if earlier the date it is sent via certified United States mail.

19. Waiver of Notice. Any person entitled to notice hereunder may waive such notice in writing.

20. Information Confidential. As partial consideration for the granting of the Award hereunder, you hereby agree to keep confidential all information and knowledge, except that which has been disclosed in any public filings required by law, that you have relating to the terms and conditions of this Agreement; *provided, however*, that such information may be disclosed as required by law and may be given in confidence to your spouse and tax and financial advisors. In the event any breach of this promise comes to the attention of the Company, it shall take into consideration that breach in determining whether to recommend the grant of any future similar award to you, as a factor weighing against the advisability of granting any such future award to you.

21. Successors. This Agreement shall be binding upon you, your legal representatives, heirs, legatees and distributees, and upon the Company, its successors and assigns, including, but not limited to, any successor entity resulting from a Change in Control.

22. Severability. If any provision of this Agreement is held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining provisions hereof, but such provision shall be fully severable and this Agreement shall be construed and enforced as if the illegal or invalid provision had never been included herein.

23. Company Action. Any action required of the Company shall be by authority of the Board or by a person or entity authorized to act by the Board.

24. Headings. The titles and headings of Sections are included for convenience of reference only and are not to be considered in construction of the provisions hereof.

25. Governing Law. All questions arising with respect to the provisions of this Agreement shall be determined by application of the laws of Texas, without giving any effect to

any conflict of law provisions thereof, except to the extent Texas state law is preempted by federal law. The obligation of the Company to sell and deliver Stock hereunder is subject to applicable laws and to the approval of any governmental authority required in connection with the authorization, issuance, sale, or delivery of such Stock.

26. Consent to Texas Jurisdiction and Venue. You hereby consent and agree that state courts located in Harris County, Texas and the United States District Court for the Southern District of Texas each shall have personal jurisdiction and proper venue with respect to any dispute between you and the Company arising in connection with the Award or this Agreement. In any dispute with the Company, you will not raise, and you hereby expressly waive, any objection or defense to any such jurisdiction as an inconvenient forum.

27. Amendment. This Agreement may be amended by the Board or by the Committee at any time (a) if the Board or the Committee determines, in its sole discretion, that amendment is necessary or advisable in light of any addition to or change in any federal or state tax or securities law or other law or regulation, which change occurs after the Date of Grant and by its terms applies to the Award; or (b) other than in the circumstances described in clause (a) or provided in the Plan, with your consent.

28. Transfer. This Agreement and the Restricted Stock Units granted hereunder will not be transferable by you other than by will or the laws of descent and distribution, or as otherwise provided by the Plan.

29. The Plan. This Agreement is subject to all the terms, conditions, limitations and restrictions contained in the Plan.

30. The Policy. This Agreement and this Award is subject to all the terms, conditions, limitations and restrictions contained within the Policy.

31. Clawback. To the extent required by applicable law or any applicable securities exchange listing standards, or as otherwise determined by the Committee, this Award and amounts or shares paid or payable pursuant to or with respect to this Award shall be subject to the provisions of any applicable clawback policies or procedures adopted by the Company or its affiliates, which clawback policies or procedures may provide for forfeiture, repurchase and/or recoupment of this Award and amounts or shares paid or payable pursuant to or with respect to such Award. Notwithstanding any provision of the Agreement to the contrary, the Company reserves the right, without your consent or the consent of any beneficiary of this Award, to adopt any such clawback policies and procedures, including such policies and procedures applicable to this Agreement with retroactive effect. Your acceptance of this Award shall constitute your agreement (1) to be bound by such clawback policies or procedures and (2) to not seek indemnification or contribution from the Company for any amounts clawed back.

W&T OFFSHORE, INC.

By: /s/ Jamie L. Vazquez
Jamie L. Vazquez, President

Appendix A

Performance Goals for 2015 Award

The Performance Goals for your Restricted Stock Units shall be comprised of the business criterion noted below. Subject to the achievement of the applicable Performance Level (defined below) for the applicable performance period and resulting adjustments under Section 3(b) of the Agreement, your Restricted Stock Units, as adjusted, will become Vested Units on the Vesting Date, only if you have been an employee or service provider of the Company or of a Subsidiary continuously from the Date of Grant through the Vesting Date. The applicable Scale between the Performance Levels on the charts below will be calculated using straight-line interpolation. The Committee shall review, analyze and certify the achievement of the Performance Level for each business criteria for the applicable performance period and shall determine whether the Performance Vesting Requirement has been met, in accordance with the Agreement and the terms of the Plan. For determination of meeting the Performance Vesting Requirement, the Performance Level achieved for the applicable performance period shall be deemed achieved effective as of the last day of the applicable performance period, despite any delay that may occur in determining which Performance Level is met during the Committee's certification process.

Business Criteria

Criteria	Percentage of 100% of Restricted Stock Units Which are Subject to Performance Criteria	Performance Period
Adjusted EBITDA(1) for the Performance Period, but taking into account the effect of property sales, if applicable as deemed by the Compensation Committee (Measurement rounded to nearest million)	40%	The full calendar year, from January 1 to December 31, 2015

Performance Level (\$000)	Scale
("Target"): \$268,700 or greater	100%
\$200,000	75%
\$100,000	50%
less than \$100,000	0%

The percentage you receive on each individual scale shall be determined using straight-line interpolation.

(1) We define EBITDA as net income plus income tax expense, net interest expense, depreciation, depletion, amortization, and accretion. Adjusted EBITDA excludes the unrealized gain or loss related to our derivative contracts, contract option fee, gain or loss on extinguishment of debt, gains or losses in connection with litigation settlements, gains and losses on the sale of assets and other items that are, in the sole discretion of the Compensation Committee appropriate adjustment to reflect normalized results.

Criteria	Percentage of 100% of Restricted Stock Units Which are Subject to Performance Criteria	Performance Period
Adjusted EBITDA Margin Percentage for the Performance Period (Measurement rounded to nearest 1/10 th decimal)	60%	The full calendar year, from January 1 to December 31, 2015

Performance Level	Scale
43% or greater (“Target”)	100%
42%	75%
41%	50%
40%	25%
<40%	0%

The percentage you receive on each individual scale shall be determined using straight-line interpolation.

Executive (2015): 12

W&T Offshore, Inc.

Ratio of Earnings to Fixed Charges

The following table sets forth our ratios of consolidated earnings to fixed charges for the periods presented:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands except ratios) (unaudited)				
Income (loss) before income taxes	\$ (1,247,702)	\$ (16,120)	\$ 80,096	\$ 119,531	\$ 264,334
Add: Fixed charges	104,870	87,193	85,902	63,441	52,581
Add: Amortization of capitalized interest	5,533	4,538	4,380	1,526	1,037
Less: Capitalized Interest	(7,256)	(8,526)	(10,058)	(13,274)	(9,877)
Earnings before fixed charges	<u>\$ (1,144,555)</u>	<u>\$ 67,085</u>	<u>\$ 160,320</u>	<u>\$ 171,224</u>	<u>\$ 308,075</u>
Fixed Charges:					
Interest expense, net of capitalized interest	\$ 97,336	\$ 78,396	\$ 75,581	\$ 49,994	\$ 42,516
Capitalized interest	7,256	8,526	10,058	13,274	9,877
Portion of rental expense representative of an interest factor	278	271	263	173	188
Total fixed charges	<u>\$ 104,870</u>	<u>\$ 87,193</u>	<u>\$ 85,902</u>	<u>\$ 63,441</u>	<u>\$ 52,581</u>
Ratio of earnings to fixed charges	<u>N/A (1)</u>	<u>N/A (2)</u>	<u>1.9</u>	<u>2.7</u>	<u>5.9</u>

(1) The ratio was not meaningful. Earnings were inadequate to cover fixed charges for the year ended December 31, 2015 by \$1,249.4 million, which included a ceiling test write-down of oil and gas properties of \$987.2 million.

(2) The ratio was less than one-to-one coverage. Earnings were inadequate to cover fixed charges for the year ended December 31, 2014 by \$20.1 million.

SUBSIDIARIES OF W&T OFFSHORE, INC.

The subsidiaries of W&T Offshore, Inc. are listed below.

Name	State of Organization	Percent Owned
W & T Energy VI, LLC	Delaware	100.0%
W & T Energy VII, LLC	Delaware	100.0%
White Shoal Pipeline Corporation	Delaware	73.4%

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

- (1) Registration Statement (Form S-3 Nos. 333-202946) of W&T Offshore, Inc.,
- (2) Registration Statement (Form S-8 Nos. 333-188584) pertaining to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, and
- (3) Registration Statement (Form S-8 No. 333-126252) pertaining to the W&T Offshore, Inc. 2004 Directors Compensation plan;

of our reports dated March 9, 2016, with respect to the consolidated financial statements of W&T Offshore, Inc. and subsidiaries, and the effectiveness of internal control over financial reporting of W&T Offshore, Inc. included in this Annual Report (Form 10-K) for the year ended December 31, 2015.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 9, 2016

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Tracy W. Krohn, certify that:

1. I have reviewed this Annual Report on Form 10-K of W&T Offshore, Inc. (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2016

/s/ TRACY W. KROHN

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

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John D. Gibbons, certify that:

1. I have reviewed this Annual Report on Form 10-K of W&T Offshore, Inc.(the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 9, 2016

/s/ JOHN D. GIBBONS

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

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of W&T Offshore, Inc. (the "Company"), hereby certifies, to the best of his knowledge, that the Company's Annual Report on Form 10-K for the year ended December 31, 2015 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 9, 2016

/s/ TRACY W. KROHN

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

Date: March 9, 2016

/s/ JOHN D. GIBBONS

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

February 2, 2016

Exhibit 99.1

Mr. James A. Glanzer
W&T Offshore, Inc.
1100 Poydras Street, Suite 1100
New Orleans, Louisiana 70163

Dear Mr. Glanzer:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2015, to the W&T Offshore, Inc. (W&T) interest in certain oil and gas properties located onshore Texas; in state waters offshore Alabama, Louisiana, and Texas; and in federal waters in the Gulf of Mexico. W&T finalized the sale of the majority of its interest in Spraberry Field in October 2015; it is our understanding that W&T retained a small overriding royalty interest in these Spraberry Field properties that are included in this report. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by W&T. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, except that future income taxes are excluded and, as requested, abandonment costs have not been included in our estimates of future net revenue. Definitions are presented immediately following this letter. This report has been prepared for W&T's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the W&T interest in these properties, as of December 31, 2015, to be:

Category	Net Reserves			Future Net Revenue ⁽¹⁾ (M\$)	
	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	23,867.5	5,705.6	168,065.9	985,055.4	774,876.4
Proved Developed Non-Producing	5,583.4	680.6	30,446.5	192,957.1	127,756.8
Proved Undeveloped	<u>6,073.7</u>	<u>207.6</u>	<u>6,903.3</u>	<u>117,185.9</u>	<u>62,998.0</u>
Total Proved	35,524.6	6,593.8	205,415.6	1,295,198.2	965,631.3

Totals may not add because of rounding.

(1) Future net revenue does not include estimated abandonment costs.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is W&T's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for W&T's share of state production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2015. For oil and NGL volumes, the average Plains Marketing, L.P. West Texas Intermediate posted price of \$46.79 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Platts *Gas Daily* Henry Hub spot price of \$2.587 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are \$46.94 per barrel of oil, \$17.60 per barrel of NGL, and \$2.499 per MCF of gas.

Operating costs used in this report are based on operating expense records of W&T. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and W&T's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by W&T and are based on authorizations for expenditure (AFEs) prepared for internal approval and, if applicable, external interest owner approval. If an AFE was not available, W&T provided cost estimates based on recent activity similar in scope to the proposed project. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of W&T's future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the W&T interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on W&T receiving its net revenue interest share of estimated future gross production after field usage and shrinkage.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by W&T, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be

more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, petrophysical data, seismic data, well test data, production data, bottomhole pressure data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from W&T, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Thomas M. Souers, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1991 and has over 14 years of prior industry experience. Ruurdjan (Rudi) de Zoeten, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 18 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III

By: C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Ruurdjan (Rudi) de Zoeten

By: Ruurdjan (Rudi) de Zoeten, P.G. 3179
Vice President

/s/ Thomas M. Souers

By: Thomas M. Souers, P.E. 65160
Vice President

Date Signed: February 2, 2016

Date Signed: February 2, 2016

TMS:ARS

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4 -10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
- (iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
- (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
- (iii) Dry hole contributions and bottom hole contributions.
- (iv) Costs of drilling and equipping exploratory wells.
- (v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

- (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
- (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
- (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
 - (1) Lifting the oil and gas to the surface; and
 - (2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
- (D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

- a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
- b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

- (A) Transporting, refining, or marketing oil and gas;
- (B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
- (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
- (D) Production of geothermal steam.

(17) *Possible reserves*. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

- (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
- (iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
- (iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
- (v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
- (vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

- (i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
- (ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
- (iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
- (iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

- (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:
 - (A) Costs of labor to operate the wells and related equipment and facilities.
 - (B) Repairs and maintenance.
 - (C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

- (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
 - (E) Severance taxes.
- (ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.
- (21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.
- (22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
- (i) The area of the reservoir considered as proved includes:
 - (A) The area identified by drilling and limited by fluid contacts, if any, and
 - (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
 - (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
 - (iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
 - (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
 - (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
 - (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
 - (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
- (23) *Proved properties.* Properties with proved reserves.
- (24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90%

OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:	
932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:	
<input type="checkbox"/>	a.Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
<input type="checkbox"/>	b.Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).
The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.	
932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:	
<input type="checkbox"/>	a.Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
<input type="checkbox"/>	b.Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
<input type="checkbox"/>	c.Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
<input type="checkbox"/>	d.Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
<input type="checkbox"/>	e.Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
<input type="checkbox"/>	f.Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources*. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well*. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well*. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves*. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
- The company's historical record at completing development of comparable long-term projects;
- The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
- The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
- The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

- (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties*. Properties with no proved reserves.