W&T OFFSHORE INC
Form 10-K
March 09, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

þ 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)	72-1121985 (I.R.S. Employer Identification Number)
Nine Greenway Plaza, Suite 300	
Houston, Texas (Address of principal executive offices)	77046-0908 (Zip Code)

(713) 626-8525

(Registrant's telephone number, including area code)

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 þ

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 þ

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 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 þ 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. þ

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

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

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

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.

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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 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 (Dantzler) 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

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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

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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.

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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 Colombia 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 (Mcfe/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 Mcfe/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 (Mcfe/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	Mcf – thousand cubic feet
MBbls – thousand barrels for crude oil, condensate or NGLs	

	MMcf – million cubic feet
MBoe – thousand barrels of oil equivalent	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 (Mcfe/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 ($/Mcfe)	2.73	4.26	3.99
Average production costs: (1)			
Oil equivalent ($/Boe)	$8.96	$10.73	$12.46
Natural gas equivalent ($/Mcfe)	1.49	1.79	2.08

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

Volume measurements:

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

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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 (Dantzler). 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.

				Total Energy-Equivalent Reserves [2]			
Classification of Proved Reserves [1]	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	Bcf – billion cubic feet
MMBoe – million barrels of oil equivalent	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   MMcf – million cubic feet

MBoe – thousand barrels of oil equivalent   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.

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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	7	18	9
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	3.1	16.4	8.9

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 Aviara 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 "WTI". 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.

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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.

Period	Total Number of Restricted Stock Units Delivered	Average Price per Restricted Stock Unit	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
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	507,265	948,708	984,088	874,491	971,047
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	1,652,968	886,640	837,357	705,181	641,587
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)	$(1,044,718)	$(11,661)	$51,322	$71,984	$172,817
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

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	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	Bcf – billion cubic feet
MMBoe – million barrels of oil equivalent	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 (Mcfe/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
	$39.89	$50.48	$46.08	$40.35	$38.02
Average per Mcfe ($/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
	$6.64	$8.41	$7.68	$6.73	$6.34
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	Mcf – thousand cubic feet
Boe – barrel of oil equivalent	MMcf – million cubic feet
MBbls – thousand barrels for crude oil, condensate or NGLs	MMcfe – million cubic feet equivalent
MBoe – thousand barrels of oil equivalent	

DD&A - depreciation, depletion, amortization and accretion

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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.

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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 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	$230,161	$626,612	$634,378

(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	$212,268	$525,584	$507,067

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 results 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

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- 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

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

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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	December 31, 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	$1,208,022	$2,689,508
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;	1	1

78,768,588 issued and 75,899,415 outstanding at December 31, 2014		
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)	$1,208,022	$2,689,508

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	1,652,968	886,640	837,357
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)	$(1,044,718)	$(11,661)	$51,322
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	Retained Earnings	Treasury Stock		Total Shareholders' Equity
	Shares	Value	Capital	(Deficit)	Shares	Value	(Deficit)
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)	—	—					