W&T OFFSHORE INC
Form 10-K
March 07, 2014

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, 2013

or

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

Texas (State of incorporation)	72-1121985 (IRS Employer Identification Number)
Nine Greenway Plaza, Suite 300	
Houston, Texas (Address of principal executive offices)	77046-0908 (Zip Code)

(713) 626-8525

(Registrant’s telephone number, including area code)

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. ¨

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 $497,201,000 based on the closing sale price of $14.29 per share as reported by the New York Stock Exchange on June 28, 2013.

The number of shares of the registrant's common stock outstanding on March 5, 2014 was 75,591,699.

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 primarily in the Gulf of Mexico and Texas. 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-own subsidiary, W&T Energy VI, LLC.

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 historic 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.

Our onshore activities have been primarily in the Permian Basin of West Texas, where most of our leasehold interests were acquired in a single 2011 acquisition. We have had limited activity in East Texas, where we acquired leasehold interests in 2011, and have been evaluating the area through selective exploration and development efforts.

As of December 31, 2013, we have interests in offshore leases covering approximately 1.1 million gross acres (0.7 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. Onshore, we have leasehold interests in approximately 0.2 million gross acres (0.2 million net acres), substantially all of which are in Texas. Approximately 57% of our total net offshore acreage is developed and approximately 13% of our total net onshore acreage is developed. Of the onshore leasehold acreage classified as undeveloped, a substantial portion could expire in 2014 but is expected to be extended by drilling two additional wells in 2014 and can be further extended by additional operations or production in future years.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent petroleum consultant, our total proved reserves at December 31, 2013 were 117.7 million barrels of oil equivalent ("MMBoe") or 705.9 billion cubic feet equivalent ("Bcfe"). Approximately 51% of our reserves were classified as proved developed producing, 22% as proved developed non-producing and 27% as proved undeveloped. Classified by product, our reserves at December 31, 2013 were 50% oil, 13% natural gas liquids ("NGLs") and 37% 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 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 $2.5 billion. Our PV-10 after considering future cash outflows related to asset retirement obligations ("ARO") and without deducting future income taxes was $2.3 billion, and our standardized measure of discounted future cash flows was $1.7 billion as of December 31, 2013. Neither PV-10 nor PV-10 after ARO are financial measures 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 of this Form 10-K.

We seek to increase our reserves through acquisitions, 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 continues to work diligently to find properties that will fit our profile and that we believe will add strategic and financial value to our company.

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"). Internal estimates of proved reserves associated with the Callon Properties as of the acquisition dates were approximately 2.1 MMBoe (12.7 Bcfe), comprised of approximately 67% oil and 33% natural gas, all of which were classified as proved developed.

In October 2012, we acquired from Newfield Exploration Company and its subsidiary, Newfield Exploration Gulf Coast LLC (together, "Newfield"), certain oil and gas leasehold interests in the Gulf of Mexico (the "Newfield Properties"). Internal estimates of proved reserves associated with the Newfield Properties as of the acquisition date were approximately 7.0 MMBoe (42.0 Bcfe), comprised of approximately 61% natural gas, 36% oil and 3% NGLs, all of which were classified as proved developed.

In May 2011, we acquired from Opal Resources LLC and Opal Resources Operating Company LLC (collectively, “Opal”) certain oil and gas leasehold interests in the Permian Basin of West Texas (the “Opal Properties”). Internal estimates of proved reserves associated with the Opal Properties as of the acquisition date were approximately 30.1 MMBoe (180.4 Bcfe), comprised of approximately 69% oil, 22% NGLs and 9% natural gas, and approximately 70% of such reserves were classified as proved undeveloped. We also acquired additional leasehold interest in the area (collectively, the “Spraberry field”).

In August 2011, we acquired from Shell Offshore Inc. (“Shell”) its 64.3% interest in the Fairway field along with a like interest in the associated Yellowhammer gas treatment plant (collectively, the “Fairway Properties”). Internal estimates of proved reserves associated with the Fairway Properties as of the acquisition date were 8.9 MMBoe (53.5 Bcfe), comprised of approximately 72% natural gas, 27% NGLs and less than 1% oil, all of which were classified as proved developed producing.

From time to time, as part of our business strategy, we sell various properties. 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. In 2012, we sold our non-operated working interest in the South Timbalier 41 field located in the Gulf of Mexico. In 2011, there were no property sales of significance.

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

Our exploration efforts historically have been in areas in reasonably close proximity to known proved reserves, but in 2013, some of our exploration projects were higher risk deepwater projects with potentially higher returns than our previous risk/reward profile. Historically, we have financed our drilling capital expenditures with operating cash flow. 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 the oil and natural gas industry and our business, 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. Onshore wells are less capital intensive than offshore wells, but the amount of reserves discovered and developed on a per well basis has historically been less from onshore wells than from offshore wells. We completed five, four and eight offshore wells (gross) in 2013, 2012 and 2011, respectively and completed 40, 77 and 39 onshore wells (gross) in 2013, 2012 and 2011, respectively.

We generally sell our 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.

Our total capital expenditure budget for 2014 currently is $450.0 million, not including any potential acquisitions. The budget includes 42% for exploration, 52% for development and 6% for other items. Geographically, the budget is split 68% for offshore and 32% for onshore. Thus far in 2014, we have not closed any acquisitions, but we continue to evaluate and bid on opportunities as they arise. We anticipate funding our 2014 capital budget and any potential acquisitions with cash flow from operating activities, cash on hand, borrowings under our revolving bank credit facility and by accessing the capital markets to the extent necessary. For the portion of our capital budget related to drilling, our operating policy has been to fund these expenditures with cash flow provided by operations. Our 2014 capital budget is subject to change as conditions warrant. We strive to be as flexible as possible and believe this strategy holds the best promise for value creation and growth and managing the volatility inherent in our business.

Business Strategy

We plan to continue 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 will yield desirable rates of return commensurate with our perception of risks. We believe attractive acquisition opportunities will continue to arise 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. Because of ongoing market volatility and, more specifically, the low natural gas prices occurring during the past several years, we also believe that other less well-capitalized producers may seek buyers for their properties both onshore and offshore, which could create opportunities for us.

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 usually 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.

In addition to pursuing opportunities in the Gulf of Mexico, we plan to continue to pursue other areas that are compatible with our technical expertise and could yield desirable rates of return commensurate with our perception of risks. As described above, we have acquired interests in various onshore properties in Texas and anticipate acquiring or expanding our onshore holdings through exploration, development and acquisition activities.

We believe our business approach has contributed to our success and has positioned us to capitalize on new opportunities. Historically, we have limited our annual capital spending for drilling activities to operating cash flow, and we have used capacity under our revolving bank credit facility for acquisitions, development and to balance working capital fluctuations.

Competition

The oil and natural gas industry is highly competitive. We currently operate in the Gulf of Mexico and onshore in Texas 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 and 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. For a more thorough discussion of how competition could impact our ability to successfully complete our business strategy, see Risk Factors in Part I, Item 1A of this Form 10-K.

Oil and Natural Gas Marketing and Delivery Commitments

We sell our oil, NGLs and natural gas to third-party purchasers. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers. However, in 2013 approximately 48% of our sales were to Shell Trading (US) Co. and no other customer comprised greater than 10% of our sales. See Financial Statements – Note 1 – Significant Accounting Policies – Concentration of Credit Risk in Part II, Item 8 of this Form 10-K for additional information about our sales to customers. Due to the nature of oil and natural gas markets and because oil and natural gas are freely traded commodities with numerous purchasers in the Gulf of Mexico and Texas, we do not believe the loss of a single purchaser or a few purchasers would materially affect our ability to sell our production. We do not have any 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 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.

In addition, 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 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. 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.

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 Outer Continental Shelf Lands Act ("OCSLA"), which is administered by the Bureau of Ocean Energy Management ("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. On June 18, 2008, the BOEM issued a final rule, effective August 18, 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 1, 2009, such sales and purchases to the FERC. 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 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 recently pursued by the FERC and Congress will continue.

While the changes by these federal and state regulators for the most part affect us only indirectly, they are intended to further 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 oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for oil, NGLs and other products are regulated by the FERC. The FERC has established an indexing system for such transportation, which 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. 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.

Federal leases. Most of our offshore operations are conducted on federal oil and natural gas leases, which are administered by the BOEM pursuant to the OCSLA. These leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed BOEM, Bureau of Safety and Environmental Enforcement ("BSEE"), and other government agency regulations and orders that are subject to interpretation and change. The BOEM and BSEE have promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures and pipelines. See Risk Factors under Part I, Item 1A in this Form 10-K for more information on new regulations and interpretations.

To cover the various obligations of lessees on the OCS, the BOEM generally requires that lessees demonstrate financial strength and reliability according to regulations or post bonds or other acceptable assurances that such obligations will be satisfied. The cost of these bonds or assurances can be substantial, and there is no assurance that they can be obtained in all cases. Under some circumstances, the BOEM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations. In addition, the BOEM can require supplemental bonding from operators for decommissioning, plugging, and abandonment liabilities. According to federal regulations, the BOEM will waive its supplemental bonding requirements when a lessee or its guarantor can demonstrate the financial capability and reliability to meet these obligations. The parent company, W&T Offshore, Inc. received letters in November and December 2013 from the BOEM regarding potential increases in our supplemental bonding requirements and we were granted a stay until April 15, 2014 to facilitate ongoing negotiations. See Legal Proceedings – Disqualification of waiver concerning certain supplement bonding requirements from the BOEM under Part I, Item 3 in this Form 10-K for more information.

The Office of Natural Resources Revenue ("ONRR") administers the collection of royalties under the terms of the OCSLA and the oil and natural gas leases issued thereunder. The amount of royalties due is based upon the terms of the oil and natural gas leases as well as the regulations promulgated by the ONRR and the BOEM. The ONRR has the authority to assess fines and penalties for knowing or willful non-compliance with regulations and notices. In December 2013 and January 2014, we were notified by the ONRR of an underpayment of royalties on certain Federal offshore oil and gas leases that cumulatively approximated $30,000 over several years. Based upon informal discussions with representatives of the ONRR, we believe that it is likely the ONRR will assess a statutory fine, which could be in an amount substantially in excess of the underpayment. If such an assessment is made in an amount we deem excessive, we intend to contest the fine to the fullest extent possible.

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. It is possible that similar, if not more stringent, requirements will be issued by the BOEM and/or the BSEE for future hurricane seasons. New requirements, if any, could increase our operating costs and/or capital expenditures.

Environmental Regulations

General. We are subject to 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 natural 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.

In November 2013, the parent company, W&T Offshore, Inc., received notices of debarment from the U.S. Environmental Protection Agency (the “EPA”) related to environmental violations that occurred in 2009. The debarment is a three-year suspension from acquiring any federal leases in the Gulf of Mexico and from participating in any federal lease sales including those in the Gulf of Mexico. See Legal Proceedings under Part I, Item 3 in this Form 10-K for more information. We believe our operations are currently in substantial compliance with current applicable environmental laws and regulations. We believe that compliance with existing requirements will not have a material adverse impact on our operations, but failure to comply could cause material consequences to our business. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have additional material adverse effects upon our business, including the further suspension or cessation of operations in affected areas. As such, there can be no assurance that material cost and liabilities related to compliance with environmental laws and regulations will not be incurred in the future.

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. In addition, companies that incur liability frequently also confront third-party claims because it is not uncommon for neighboring landowners and other third parties to file 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. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties.

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, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from the RCRA definition of "hazardous wastes," thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating costs as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted. 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. Air emissions from our operations are subject to the 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. For example, in August 2012, the EPA adopted new rules that established air emission controls requirements for oil and natural gas production and natural gas processing operations. Specifically, the EPA established New Source Performance Standards for emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards for hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA rules require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of “green completions” for hydraulic fracturing, which requires the operator to recover rather than vent any hydrocarbons that come to the surface during completion of the fracturing process. The requirement for flaring of gas not sent to a gathering line became effective in October 2012, and all operators are required to use “green completions” drilling equipment beginning January 2015. The rules also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants. These rules may require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our operating results. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

Climate Change. In December 2009, the EPA 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 warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun 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 requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2011. The EPA also requires the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis. We believe we are in compliance with this new emission reporting requirement as it applies to our operations.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half 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, NGLs 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. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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. OPA also 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. OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the OCS, although the Secretary of Interior may increase this amount up to a maximum of $150 million. 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. 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.

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 we believe we are in substantial compliance with their terms.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand or other proppants and chemicals under pressure into the formation to fracture the rock formation and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act (the "SDWA") over certain hydraulic fracturing activities involving the use of diesel fuel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. We follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities including disclosure requirements.

Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells that require hydraulic fracturing.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and the EPA is performing a study of the potential environmental effects of hydraulic fracturing on drinking water resources. The EPA's study includes 18 separate research projects addressing topics such as water acquisition, chemical mixing, well injection, flowback and produced water, and wastewater treatment and disposal. The EPA has indicated that it expects to issue its study report in 2014. The EPA is also developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by late 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

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). The BSEE also issues numerous regulations under the nomenclature Notice to Lessees ("NTL") that provide formal guidelines on implementation of OCS regulations and standards. We believe we are in compliance in all material respects with the requirements regarding protection of marine species.

Certain flora and fauna that have been officially classified as "threatened" or "endangered" are protected by the Endangered Species Act. This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area where we wish to conduct seismic surveys, development or abandonment operations, the work could be prohibited or delayed or expensive mitigation could be required.

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. 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.

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.

We maintain liability insurance and well control insurance for all of our operations. In addition, we maintain property and hurricane damage insurance coverage for some, but not all, of our properties, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain does not cover the risks described above from gradual pollution events which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover such risks or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant environmental 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 and Insurance Claims in Part II, Item 7 of this Form 10-K for additional information on insurance coverage.

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 of this Form 10-K.

Employees

As of December 31, 2013, we employed 333 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 the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil, NGLs and natural gas prices may 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 oil, NGLs and natural gas production directly affects our revenues, profitability, access to capital and future rate of growth. Oil, NGLs and natural gas are commodities and are subject to wide price fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for 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 oil, NGLs and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign 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 activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global 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.

Lower prices for our oil, NGLs and natural gas production may not only decrease our revenues on a per unit basis but may also reduce the amount of oil, NGLs and natural gas that we can produce economically. For example, the prices of oil and natural gas declined substantially during the second half of 2008 and impacted production volumes. 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. There have been significant recent development activities in shale and other resource plays, which 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 increased 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 depressed oil, NGLs and natural gas prices would materially and adversely affect our future business, financial condition, results of operations, liquidity and/or ability to finance planned capital expenditures.

If oil, NGLs and natural gas prices decrease, we may be required to 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 periodically review the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. As a result of the decline in both oil and natural gas prices during 2009, we recorded a ceiling test impairment of $218.9 million. We have not had any ceiling test impairments since 2009. Declines in oil, NGLs and natural gas prices after December 31, 2013 may require us to record additional ceiling test impairments in the future. No assurance can be given that we will not experience a ceiling test impairment in future periods, which could have a material adverse effect on our results of operations in the period taken. As a result of lower oil, NGLs and natural gas prices, we may also reduce our estimates of the reserves 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 – Critical Accounting Policies – Impairment of oil and natural gas properties in Part II, Item 7 and Financial Statements – Note 1 – Significant Accounting Policies in Part II, Item 8 of this Form 10-K for additional information on the ceiling test.

The Company could pay additional penalties and certain operating activities could be restricted if it does not comply with the terms of an agreement with certain government entities.

The United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the EPA conducted a federal grand jury investigation beginning in late 2010 of environmental law violations that occurred in 2009. In December 2012, an agreement was reached that resolved these environmental compliance matters and the agreement was approved by the federal district court in January 2013. Under the agreement, the Company on January 3, 2013 (i) pled guilty to one felony count under the Clean Water Act for altering monthly produced water discharge samples for the Ewing Banks 910 platform in 2009 and one misdemeanor count under the Clean Water Act for failure to report the discharge of a small amount of oil from the same platform in November 2009, (ii) paid a $0.7 million fine and $0.3 million for community service and (iii) entered into an environmental compliance program subject to a third-party audit. Under the agreement, the Company was placed on a three-year term of probation. The probation terms require that the Company commit no further environmental law violations, comply with an Environmental Compliance Plan during the probation period and take no adverse action against personnel who cooperated in the investigation. The agreement further stipulates that the Government will not seek any further criminal charges against the Company in this matter. Failure to comply with the terms of the agreement could lead to further penalties and/or operating restrictions.

The parent company, W&T Offshore, Inc., is responding to notices from U.S. Government regulators that could, if not withdrawn or significantly modified, impair its ability to acquire additional interests in Federal oil and gas leases in the Gulf of Mexico or could limit its ability to receive other Federal related benefits or assistance activities related to certain of its Federal oil and gas leases.

In November 2013, the parent company, W&T Offshore, Inc., received a Notice of Suspension and Proposed Debarment and a Notice of Clean Water Act Listing from the EPA, as described in this report under Item 3 Legal Proceedings – Notice of Suspension and Debarment. The first Notice suspends the parent company and proposes a three year debarment from participation in future federal contracts, including future federal oil and gas leases, and assistance activities and renders the parent company ineligible to receive any federal contracts or approved subcontracts or to act as an agent or representative on behalf of another in such transaction, or receive certain federal benefits. The second Notice provides a narrower prohibition on federal contracts or benefits for the parent company. The Notices stemmed from the Company's previously disclosed plea agreement and corporate conviction on two criminal counts, as described above.

The Company has commenced discussions with the EPA Suspension and Debarment Official (the “EPA SDO”) and made filings to contest the limitations in both Notices and seek a resolution to remove the suspension in a cooperative fashion as soon as practicable. If the Company is not successful in its efforts to lift the debarment, the continued imposition of the suspension, a three year debarment, or the continued contracting disability from the second notice could impair its ability to acquire additional interests in federal oil and gas leases in the Gulf of Mexico or could limit W&T Offshore, Inc.’s ability to receive other federal related benefits or assistance activities related to certain of its federal oil and gas leases.

More stringent regulatory initiatives relating to offshore exploration and production activities may have an adverse effect on our results of operations, financial position and liquidity.

In April 2010, there was a fire and explosion aboard the Deepwater Horizon drilling platform operated by BP in the deep water of the Gulf of Mexico. As a result of the explosion and ensuing fire, the rig sank, causing loss of life, and created a major oil spill that produced economic, environmental and natural resource damage in the Gulf Coast region. In response to the explosion and spill, there have been many proposals, and substantial rules adopted, by governmental and private constituencies to address the direct impact of the disaster and to prevent similar disasters in the future. Beginning in 2010 and continuing through 2013, 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, has issued various rules, NTLs and temporary drilling moratoria that impose or result in added environmental and safety measures upon exploration, development and production operators in the Gulf of Mexico. These new regulatory requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.
- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.
- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.
- The Workplace Safety Rule, which requires operators to employ a comprehensive safety and environmental management system (“SEMS”) to reduce human and organizational errors as root causes of work-related accidents and offshore spills, develop protocols as to whom at the facility has the ultimate operational safety and decision-making authority, establish procedures to provide all personnel with “stop work” authority, and to have their SEMS periodically audited by an independent third party auditor approved by BSEE.

These new regulatory initiatives may serve to effectively slow down the pace of drilling and production operations in the Gulf of Mexico due to adjustments in operating procedures and certification practices as well as increased lead times to obtain exploration and production plan reviews, develop drilling applications, and apply for and receive new well permits. These new requirements also increase the cost of preparing permit applications and will increase the cost of each new well, particularly for wells drilled in deeper waters on the OCS. We could become subject to fines, penalties or orders requiring us to modify or suspend our operations in the Gulf of Mexico if we fail to comply with these requirements. Moreover, if similar oil spill incidents were to occur in the future in the Gulf of Mexico or elsewhere where we conduct operations, the relevant governmental authorities 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 regulatory initiatives regarding offshore oil and gas exploration and development activities, which any one or more of such events could have a material adverse effect on our production activities as well as our financial position, results of operations and liquidity.

New requirements imposed by the BOEM and BSEE on W&T Offshore, Inc. related to the decommissioning, plugging, and abandonment of offshore facilities could significantly impact the cost of operating our business.

In addition to the NTLs discussed previously, the BOEM issued NTL No. 2010-G05 dated effective October 15, 2010 that establishes a more stringent regimen for the timely decommissioning of what is known as “idle iron” – wells, platforms and pipelines that are no longer producing or serving exploration or support functions related to an operator’s lease – in the Gulf of Mexico. This NTL sets forth more stringent standards for decommissioning timing requirements by requiring that any well that has not been used during the past five years for exploration or production on active leases and is no longer capable of producing in paying quantities must be permanently plugged or temporarily abandoned within three years. Plugging or abandonment of wells may be delayed by two years if all of the well’s hydrocarbon and sulfur zones are appropriately isolated. Similarly, platforms or other facilities that are no longer useful for operations must be removed within five years of the cessation of operations. The triggering of these plugging, abandonment and removal activities under what may be viewed as an accelerated schedule in comparison to historical decommissioning efforts which could cause an increase, perhaps materially, in our future plugging, abandonment and removal costs, which may translate into a need to increase our estimate of future ARO required to meet such increased costs. In 2010, we increased our estimate of ARO based on our expected acceleration in timing for such obligations as a result of implementing this NTL. In 2012, after receiving further interpretations of the regulations from the BOEM, the scope of the work increased and the determination of final requirements increased the amount of work involved. As a result of this effort, along with other work scope changes, we increased our estimate of ARO again in 2012 and in 2013. The increase in decommissioning activity in the Gulf of Mexico expected over the next few years as a result of the NTL may result in increased demand for salvage contractors and equipment, resulting in increased estimates of plugging, abandonment and removal costs and increases in related ARO.

To cover the various obligations of lessees on the OCS, the BOEM generally requires that lessees demonstrate financial strength and reliability according to regulations or post bonds or other acceptable assurances that such obligations will be satisfied. The cost of these bonds or assurances can be substantial, and there is no assurance that they can be obtained in all cases. Under some circumstances, the BOEM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations. In addition, the BOEM can require supplemental bonding from operators for decommissioning, plugging, and abandonment liabilities if financial strength and reliability criteria are not met.

In November and December 2013, the parent company, W&T Offshore, Inc., received letters from the BOEM claiming that it no longer qualifies for a waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging, and abandonment liabilities. We have had continuing discussions with the BOEM staff to resolve this matter and, in order to preserve our rights, in January 2014 we filed a Petition for Stay Pending Appeal and Request for Interim Relief with the U.S. Department of Interior's Board of Land Appeals. The petition seeks a stay of any supplemental bonding requirements pending the appeal and to reverse the BOEM's revocation of W&T Offshore, Inc.'s waiver of supplemental bonding requirements. Initially, we were granted a stay until February 15, 2014 in response to our petition and recently we were granted a stay until April 15, 2014 to facilitate ongoing negotiations. We continue to believe that the parent company qualifies for a supplemental bonding waiver. We intend to continue to work with the BOEM staff to resolve this matter. If resolving this matter ultimately involves the imposition of additional bonding requirements, it will result in increased costs of conducting our offshore business and operations and could utilize a portion of the borrowing capacity available under our revolving bank credit facility.

Proposed rules regulating air emissions from oil and gas operations could cause us to incur increased capital expenditures and operating costs.

In August 2012, the EPA adopted new regulations under the CAA that, among other things, require additional emissions controls for the production of oil, NGLs and natural gas, including New Source Performance Standards to address emissions of sulfur dioxide and VOCs and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could significantly increase our costs of development and production.

Lower oil and natural gas prices could negatively impact our ability to borrow.

As of December 31, 2013, borrowing availability under our revolving bank credit facility was $800.0 million, less outstanding borrowings and letters of credit. Availability is determined semi-annually by our lenders and is based on oil, NGLs and natural gas prices and on our proved reserves. Substantially all of our oil and natural gas properties are pledged as collateral under the Fifth Amended and Restated Credit Agreement (the "Credit Agreement") governing our revolving bank credit facility. The Credit Agreement limits our ability to incur additional indebtedness based on specified financial covenants, ratios or other criteria. Lower oil, NGLs and natural gas prices in the future could result in a reduction in credit availability and also affect our ability to satisfy these covenants, ratios or other criteria and thus could reduce our ability to incur additional indebtedness and our ability to replace reserves.

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 2013, we renewed our insurance policies covering well control, hurricane damage, general liability and pollution (inclusive of brokerage fees) at an annual cost of approximately $23.6 million. A per-occurrence retention amount of $30.0 million for named windstorm events must be satisfied by us before our insurers will indemnify us for losses and we co-insure 25% of our named windstorm coverage. These policies expire in May and June 2014. 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. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. See Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims and – Note 18 – Contingencies under Part II, Item 8 of this Form 10-K for additional information on legal issues regarding our 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.

Due to insurance claims in recent years associated with hurricanes in the Gulf of Mexico and global catastrophic losses, property damage and well control insurance coverage has become more limited and the cost of such coverage has become both more costly and more volatile. The insurance market may change dramatically in the future due to the major oil spill that occurred in 2010 at BP's Macondo well in the deepwater Gulf of Mexico. As of December 31, 2013, approximately 88% of our PV-10 value of proved reserves attributable to our Gulf of Mexico properties is on platforms that are covered under our current insurance policies for named windstorm damage. 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 may 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 oil and natural gas prices, they may also limit future income if 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 – Note 6 – Derivative Financial Instruments under Part II, Item 8 of this Form 10-K for additional information on derivative transactions.

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 scheduled 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. Further, 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.

As of December 31, 2013, approximately 27% of our total proved reserves were undeveloped and approximately 22% of our total proved reserves were developed non-producing. There can be no assurance that all of those reserves will ultimately be developed or produced.

We are not the operator with respect to approximately 9% of our proved developed non-producing 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 and developed non-producing reserves 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.

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. By their nature, estimates of undeveloped reserves are less certain. Recovery of undeveloped reserves could require significant capital expenditures and successful drilling operations. Our future oil and natural gas reserves, production, and therefore our cash flow and net income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable 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. Production from reservoirs in the Gulf of Mexico generally decline more rapidly than from reservoirs in many other producing regions of the United States. Our independent petroleum consultant estimates that 39% 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.

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. In order to finance future capital expenditures, we may need to alter or increase our capitalization substantially through the issuance of additional debt or equity securities, bank borrowings, reserve-based loans, joint ventures or other means. These changes in capitalization may significantly affect our financial risk profile.

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. If our cash flow from operations and cash on hand are not sufficient to fund our capital expenditure budget, we may not be able to access additional debt, equity or other methods of financing on an economic or timely basis to replace our proved reserves.

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. 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 and to consummate transactions in a highly competitive environment. 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 may put us at a competitive disadvantage for acquiring properties. These risks are described above in the risk factors titled:

- The parent company, W&T Offshore, Inc., is responding to notices from U.S. Government regulators that could, if not withdrawn or significantly modified, impair its ability to acquire additional interests in Federal oil and gas leases in the Gulf of Mexico or could limit its ability to receive other Federal related benefits or assistance activities related to certain of its Federal oil and gas leases.
- New requirements imposed by the BOEM and BSEE on W&T Offshore, Inc. related to the decommissioning, plugging, and abandonment of offshore facilities could significantly impact the cost of operating our business.

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 and limited availability, as compared to the rigs used in shallower water. Deepwater wells have greater mechanical risks because the wellhead equipment is installed on the sea floor. Deepwater development costs can be significantly higher than development costs for wells drilled on the conventional shelf because deepwater drilling requires larger installation equipment, sophisticated sea floor production handling equipment, expensive state-of-the-art platforms and investment in infrastructure. 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 more restrictive interpretation, 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.

As described above in the risk factor titled “New requirements imposed by the BOEM and BSEE related to the decommissioning, plugging, and abandonment of offshore facilities could significantly impact the cost of operating our business,” the BOEM’s NTL 2010-G05 increased our liability for ARO by accelerating the time frame for plugging, abandonment and removal for some of our platforms and the BOEM further increased our liability after issuing regulation interpretations which affected scope and requirements. In addition, the potential increase in decommissioning activity in the Gulf of Mexico over the next several years as a result of the NTL could likely result in increased demand for salvage contractors and equipment, resulting in increased estimates of plugging, abandonment and removal costs and increases in related ARO.

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.

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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 which include, among other things, hydraulic fracturing, 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. 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;

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- 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; or
- 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 relatively 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.

As we increase our onshore operations, we will be subject to different risk factors that could impact loss of revenues or curtailment of production for these geographies.

Onshore oil and gas exploration and production operations share similar risk factors to offshore, but also have some different regulations, interpretation of regulations and enforcement by the particular state in which the operations are conducted. Until 2011, our experience has primarily been with offshore operations. We are subject to and must comply with the various state regulations and work effectively with the state agencies, and failure to do so may impact our operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. We utilize hydraulic fracturing techniques in connection with developing our properties in the Spraberry field and other onshore properties. The process involves the injection of water, sand or other proppants and chemicals under pressure into the rock formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. The EPA, however, recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA Underground Injection Control Program. In addition, the EPA has commenced a broad study of the potential environmental effects of hydraulic fracturing activities, and the agency has indicated that it expects to issue its study report in late 2014. A number of other federal agencies, including the U.S. Department of Energy, Department of Interior, and White House Council on Environmental Quality, are also studying various aspects of hydraulic fracturing. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. From time to time, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states and local governments have adopted, and other states and local governments are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations, including states in which we operate. For example, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to associated permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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 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 or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities associated with such risks. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

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

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

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

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

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of our reserves at December 31, 2013. See Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Oil and natural gas reserve quantities, Part II, Item 7 for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in Business in Part I, Item 1, Properties in Part I, Item 2 and Financial Statements – Note 21 – Supplemental Oil and Gas Disclosures in Part II, Item 8 of 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 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, 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. 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. 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, 2013, 11 fields, accounting for approximately 12.3 Bcfe (or 11%) of our 2013 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 natural gas or oil, 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 natural gas and oil, 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, a third-party pipeline used by our Main Pass 108 field was shut down between June 2010 and March 2011. We estimate this shut down caused us to defer production of approximately 4.9 Bcfe during 2010 and 3.7 Bcfe during 2011. In 2012, various pipelines were shut down causing production deferral of approximately 1.5 Bcfe with our Matterhorn field being most significantly affected by these shutdowns. 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.

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 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, Part I, Item 1 of this Form 10-K for a more detailed explanation of our regulatory risks.

Our operations may incur substantial liabilities to comply with environmental 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.

As otherwise described within this Item 1A, Risk Factors, in 2013 and in prior years, we have been subject to investigations with respect to allegations that we did not comply with applicable environmental laws and regulations. In December 2012, we reached an agreement with respect to the previously disclosed federal grand jury investigation related to certain violations of environmental laws and regulations.

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. See Business – Regulation, Part I, Item 1 of this Form 10-K for a more detailed description of our environmental risks.

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.

In December 2009, the EPA 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 has begun 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 requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2011. The EPA also adopted rules requiring the 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 addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half 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, and floods and other climatic events. If any such affects were to occur, they could have an adverse effect on our financial condition and results of operations. Please see – Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

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.

Restrictions on our ability to obtain water for our onshore operations may have an adverse effect on our financial condition, results of operations and cash available for distribution.

Water is an essential component of shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, operators in the Permian Basin have been able to purchase water from local land owners for use in their operations. According to the Lower Colorado River Authority, during 2011 Texas experienced the lowest inflows of water of any year in recorded history. Severe drought conditions persisted in 2013 and these conditions could continue in 2014. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically drill for oil and natural gas, which could have an adverse effect on our consolidated financial condition, results of operations, cash flows and reserves.

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 face security exposure, including cyber-security exposure, from unauthorized access to our facilities and computer systems. This exposure includes unauthorized access to sensitive information; malicious damage to our facilities, infrastructure, and computer systems; malicious damage to third-party facilities, infrastructure, and computer systems; safety exposure for our employees and contractors; and disruptions of our operations. Although we utilize various procedures and controls to mitigate these exposures, there can be no assurances that these procedures and controls will be sufficient to prevent such events from occurring. Cyber-security exposures in particular are evolving and include malicious software, unauthorized access to confidential data and disruptions to operations that use computers and data systems. We do not carry business interruption insurance. 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, Chief Financial Officer and Chief Accounting 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 any insurance against the loss of any of these individuals. Please read Executive Officers of the Registrant in Part I following Item 3 in this Form 10-K for more information regarding our senior management team.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

The U.S. oil and natural gas industry may experience significant shortages in the availability of certain drilling rigs as well as significant increases in the cost of utilizing drilling rigs. This could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition or results of operations. If the unavailability or high cost of rigs, equipment, supplies or personnel were particularly severe in the offshore waters of the U.S. Gulf of Mexico or Texas, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

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.

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 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 Financings

Adverse changes in the financial and credit markets could negatively impact our economic growth. In addition, declines of oil, NGLs and natural gas prices can affect our ability to obtain funding on acceptable terms or under our current credit facility. These impacts may hinder or prevent us from meeting our future capital needs and may restrict or limit our ability to increase reserves of oil and natural gas.

During 2012 and 2011, world financial markets were affected by the instability of the Euro and the uncertainty of some Euro-based countries to repay their debt. In addition, one credit agency downgraded the debt of the U.S. government. These types of events bring uncertainty to the financial markets and may produce volatility and may decrease financing availability. For example, in 2009, the global financial markets and economic conditions were severely distressed. There were concerns, both with respect to bank failures and bank liquidity, as to whether our banks would be able to meet their commitments under credit arrangements in place during that time. These concerns led to very few financing transactions being completed.

We can offer no assurance that we would be able to access the capital market on terms and conditions that would be acceptable to us, if the need were to arise. Our revolving bank credit facility is subject to a semi-annual borrowing base re-determination, and available credit could be reduced or eliminated at the sole discretion of the banks within the facility.

If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due, or we may be unable to implement our exploratory and development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. In addition, our future cash flow may become insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay off our outstanding indebtedness. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or initiatives by our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our current or any future debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

Any alternative financing plans that we undertake, if necessary, may not allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our business, financial condition and results of operations.

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 and capital expenditures, 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.

In addition, if we fail to comply with the covenants or other terms of any agreements governing our debt, our lenders will have the right to accelerate the maturity of that debt and foreclose upon the collateral, if any, securing that debt. Realization of any of these factors could adversely affect our financial condition, results of operations and cash flows.

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 potential changes of control.

Tracy W. Krohn owns and controls 39,794,239 shares of our common stock, representing approximately 52.6% of our voting interests as of February 15, 2014. As a result, Mr. Krohn has the ability to control the outcome of matters that require a simple majority of shareholders for approval and other investors, by themselves, will not be able to affect the outcome of virtually any shareholder vote. 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; 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 stockholders. 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.

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Item 2. Properties

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Our fields are located in the Gulf of Mexico, Alabama and Texas. The offshore 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 reservoirs in our onshore fields are generally characterized as having low porosity and permeability and require stimulation and artificial lift to produce. The following describes our 10 largest fields as of December 31, 2013, based on quantities of proved reserves on a natural gas equivalent basis in a descending order. At December 31, 2013, these fields accounted for approximately 83% of our proved reserves. Our interests in several of our offshore fields are owned by our wholly-owned subsidiary, W&T Energy VI, LLC. Unless indicated otherwise, "drilling" 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)		2013 Average Daily Equivalent Sales Rate (Boe/d) (1)		2013 Average Daily Equivalent Sales Rate (Mcfe/d) (1)	
				Gross	Net	Gross	Net
Spraberry (Yellow Rose)	Onshore	87	%	4,395	3,674	26,373	22,046
Ship Shoal 349 (Mahogany)	Shelf	81	%	8,395	7,093	50,369	42,556
Fairway	Shelf	28	%	5,381	2,910	32,284	17,459
Viosca Knoll 783 (Tahoe/SE Tahoe)	Deepwater	29	%	8,381	5,629	50,227	33,771
Main Pass 108	Shelf	19	%	3,456	3,033	20,733	18,200
Miss. Canyon 243 (Matterhorn)	Deepwater	75	%	4,064	4,064	24,384	24,384
Main Pass 98	Shelf	22	%	702	619	4,211	3,715
Viosca Knoll 823 (Virgo)	Deepwater	40	%	2,223	1,427	13,337	8,564
Miss. Canyon 698 (Big Bend) (2)	Deepwater	92	%	—	—	—	—
Miss. Canyon 538/582 (Medusa)(3)	Deepwater	86	%	1,165	175	6,989	1,048

(1) Mcfe/d=Thousand cubic feet equivalent per day. Boe/d= barrel of equivalent per day. The amount was determined using the energy-equivalent ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs. The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for oil, NGLs and natural gas may differ significantly.

(2) No production occurred in this field as of December 31, 2013.

(3) The data for the 2013 Average Daily Equivalent Sales Rate is based on production from the acquisition date of November 5, 2013 to December 31, 2013.

Our Fields

On December 31, 2013 we had two fields of major significance (having proved reserves which comprise 15% or more of the Company's total proved reserves, calculated on a natural gas equivalent basis). The Spraberry field (Yellow Rose) is located in the Permian Basin in West Texas and the Ship Shoal 349 field (Mahogany) is located on the conventional shelf in the Gulf of Mexico. Below is a description of these fields.

Spraberry Field (Yellow Rose).

The Spraberry field is located in the Permian Basin in West Texas. We acquired a 100% working interest in approximately 21,900 net acres in connection with the acquisition of the Opal Properties in May 2011. In separate transactions, we acquired approximately 9,500 net acres in 2011 and approximately 2,200 net acres in 2013. We are the operator for these properties. The Spraberry field was discovered in 1935 and extends over several counties in West Texas comprising about 1.6 million acres. The field is 150 miles long and 75 miles wide, and it has undergone much change and expansion over the years, both aerially and vertically. The correlative interval is now over 3,500 feet thick and includes the Clearfork, Upper Spraberry, Lower Spraberry, Dean, and Wolfcamp formations. These formations are correlative over the area but are lenticular in nature and vary in thickness, porosity, and permeability even over short distances. The general completion technique includes hydraulic fracturing and installation of sucker rod pumps. During 2013, we drilled 32 additional wells, which included five horizontal wells. During 2012, we drilled 64 additional wells, which included one horizontal well. Cumulative field production through 2013 is approximately 4.6 MMBoe (27.3 Bcfe) from our wells. In 2014, we plan to drill 25 vertical wells and seven horizontal wells. Total proved reserves associated with our interest in the Spraberry field were 38.2 MMBoe (229.3 Bcfe) at December 31, 2013, 31.6 MMBoe (189.8 Bcfe) at December 31, 2012 and 28.1 MMBoe (168.5 Bcfe) at December 31, 2011.

The following presents historical information about our produced oil, NGLs and natural gas volumes from the Spraberry field for 2013, 2012 and from the acquisition date of May 11, 2011 to December 31, 2011.

	Year Ended December 31, 2013	Year Ended December 31, 2012	May 11 - December 31, 2011
Net sales:			
Oil (MBbls)	1,075	751	452
NGLs (MBbls)	170	103	60
Natural gas (MMcf)	575	376	214
Total oil equivalent (MBoe)	1,341	916	548
Total natural gas equivalent (MMcfe)	8,047	5,496	3,289
Total oil equivalent (Boe/day)	3,674	2,503	2,333
Total natural gas equivalent (Mcfe/day)	22,046	15,016	13,997
Average realized sales prices:			
Oil ($/Bbl)	$ 93.75	$ 88.11	$ 91.09
NGLs ($/Bbl)	35.86	36.94	51.70
Natural gas ($/Mcf)	3.48	2.50	3.05
Oil equivalent ($/Boe)	81.21	77.38	82.03
Natural gas equivalent ($/Mcfe)	13.54	12.90	13.67
Average production costs (1):			
Oil equivalent ($/Boe)	$ 17.66	$ 18.92	$ 13.62
Natural gas equivalent ($/Mcfe)	2.94	3.15	2.27

(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 equivalent

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 2013 is approximately 33.9 MMBoe gross (203.4 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 as of December 31, 2013. All of the wells drilled under the 2010 Development Plan have been successful. Total proved reserves associated with our interest in this field were 22.9 MMBoe (137.7 Bcfe) at December 31, 2013, 22.7 MMBoe (136.3 Bcfe) at December 31, 2012 and 20.3 MMBoe

(121.7 Bcfe) at December 31, 2011.

The following presents historical information about our produced oil, NGLs and natural gas volumes from Ship Shoal 349 field over the past three years.

	Year Ended December 31,		
	2013	2012	2011
Net sales:			
Oil (MBbls)	1,943	960	445
NGLs (MBbls)	90	85	23
Natural gas (MMcf)	3,328	2,108	498
Total oil equivalent (MBoe)	2,589	1,397	551
Total natural gas equivalent (MMcfe)	15,533	8,380	3,305
Total oil equivalent (Boe/day)	7,093	3,816	1,509
Total natural gas equivalent (Mcfe/day)	42,556	22,896	9,055
Average realized sales prices:			
Oil ($/Bbl)	$98.69	$102.55	$101.30
NGLs ($/Bbl)	43.24	41.74	56.06
Natural gas ($/Mcf)	3.72	2.78	4.20
Oil equivalent ($/Boe)	80.39	77.24	87.97
Natural gas equivalent ($/Mcfe)	13.40	12.87	14.66
Average production costs (1):			
Oil equivalent ($/Boe)	$3.68	$6.27	$14.30
Natural gas equivalent ($/Mcfe)	0.61	1.05	2.38

(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 equivalent

The following is a description of the remainder of our top 10 properties, measured by proved reserves at December 31, 2013, three of which are located on the conventional shelf and five 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 total proved reserves, calculated on a natural gas equivalent basis).

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, from Shell in August 2011. 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, 2013, six wells have been drilled, one of which was a replacement well. Cumulative field production through 2013 is approximately 114.5 MMBoe gross (686.9 Bcfe gross). This field is a Norphlet sand dune trend development with one producing horizon at an approximate depth of 21,300 feet. During December 2013, production from this field, net to our interest, averaged 14 Bbls of oil per day, 1,024 Bbls of NGLs per day and 16,077 Mcf of natural gas per day, for total production of 3,718 Boe per day (22,309 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 2013 is approximately 93.9 MMBoe gross (563.6 Bcfe gross). The Tahoe prospect is a supra-salt (above the salt layer) 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, 2013, 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 2013, production from this field, net to our interest, averaged 280 Bbls of oil per day, 1,294 Bbls of NGLs per day and 21,161 Mcf of natural gas per day, for total production of 5,101 Boe per day (30,605 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 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, 2013, 48 wells have been drilled in this field, 30 of which were successful. Cumulative field production through 2013 is approximately 43.0 MMBoe gross (258.1 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 2013, production from this field, net to our interest, averaged 249 Bbls of oil per day, 297 Bbls of NGLs per day and 14,888 Mcf of natural gas per day, for total production of 3,027 Boe per day (18,160 Mcfe per day).

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 on Mississippi Canyon block 243. 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 2013 is approximately 23.5 MMBoe gross (141.3 Bcfe gross). This field is a supra-salt development with 17 productive horizons at depths ranging to 9,850 feet. As of December 31, 2013, 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 as of December 31, 2013. During December 2013, production from this field, net to our interest, averaged 1,981 Bbls of oil per day, 540 Bbls of NGLs per day and 15,576 Mcf of natural gas per day, for total production of 5,117 Boe per day (30,705 Mcfe per day).

Main Pass 98 Field. Main Pass 98 field consists of Main Pass blocks 98 and 180. This field is located off the coast of Louisiana approximately 55 miles east of Venice in 91 feet of water. We acquired our 100% working interest in these blocks from NCX Co LLC in 2009. The field produces from low relief, predominantly stratigraphically trapped sands located between two merging, generally south dipping faults. The productive interval is Middle Miocene Bigenerina Humblei. Cumulative field production through 2013 is approximately 4.4 MMBoe gross (26.4 Bcfe gross). As of December 31, 2013, 14 wells have been drilled, nine of which have been successful. In 2013 and 2012, no wells were drilled or recompleted. During 2012, three workovers were performed. During December 2013, production from this field, net to our interest, averaged 151 Bbls of oil per day, 88 Bbls of NGLs per day and 4,369 Mcf of natural gas per day, for total production of 967 Boe per day (5,803 Mcfe per day).

Viosca Knoll 823 Field (Virgo). Viosca Knoll 823 field is located off the coast of Louisiana, approximately 125 miles southeast of New Orleans, in 1,014 feet of water. The field area covers Viosca Knoll block 823 and Viosca Knoll block 822, with a single fixed leg production platform on Viosca Knoll block 823. Total E&P discovered the field in 1997. We acquired a 64% working interest in the field from Total E&P in 2010 and we are the operator for this property. Cumulative field production through 2013 is approximately 21.0 MMBoe gross (125.7 Bcfe gross). This field is a supra-salt development with 17 productive horizons at depths ranging to 13,335 feet. As of December 31, 2013, 14 wells have been drilled, 10 of which have been successful. During December 2013, production from this field, net to our interest, averaged 175 Bbls of oil per day, 252 Bbls of NGLs per day and 7,492 Mcf of natural gas per day, for total production of 1,676 Boe per day (10,057 Mcfe per day).

Mississippi Canyon 698 Field (Big Bend). Mississippi Canyon 698 field is located off the coast of Louisiana, approximately 160 miles southeast of New Orleans, in 7,200 feet of water. The field area covers portions of Mississippi Canyon blocks 697, 698, and 742. Noble Energy Inc. (“Noble”) discovered the field in 2012. We acquired a 20% working interest in the field from the operator, Noble, in 2012. This field is a suprasalt development with two productive horizons at depths ranging from 14,660 feet to 15,533 total vertical depth. As of December 31, 2013, one well has been drilled, which was successful. Noble is currently completing the well and reviewing various development options. As of December 31, 2013, there has been no production from this field.

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 496, 538, 582 and 583. Murphy Exploration & Production Company-USA ("Murphy") discovered the field in 1999 and commenced production in 2003. We acquired a 15% working interest in the field from Callon in November 2013 and Murphy is the operator. Production from the field is from the late Miocene to early Pliocene turbidite sand reservoirs typical for the area. As of December 31, 2013, 15 wells have been drilled in the field, with eight wells currently producing. Cumulative field production through 2013 is approximately 38.0 MMBoe gross (228.0 Bcfe gross). Murphy is currently reviewing additional drilling options. During December 2013, production from this field, net to our interest, averaged 887 Bbls of oil per day, 23 Bbls of NGLs per day and 755 Mcf of natural gas per day, for total production of 1,036 Boe per day (6,219 Mcfe per day).

Proved Reserves

Our estimated proved reserves totaled 117.7 MMBoe (705.9 Bcfe) at December 31, 2013. The mix by product was 50% oil, 13% NGLs and 37% natural gas determined using the energy-equivalent ratio noted below. Our proved reserves were estimated by NSAI, our independent petroleum consultant.

Our proved reserves are summarized below. These reserve amounts are consistent with filings we make with other federal agencies.

	As of December 31, 2013						
				Total Equivalent Reserves			
Classification of Proved Reserves (1)	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe) (2)	Natural Gas Equivalent (Bcfe) (2)	% of Total Proved	PV-10 (3) (In millions)
Proved developed producing	27.8	8.1	148.5	60.6	363.8	51 %	$ 1,895
Proved developed non-producing	8.4	3.0	84.2	25.5	152.3	22 %	482
Total proved developed	36.2	11.1	232.7	86.1	516.1	73 %	2,377
Proved undeveloped	22.3	4.8	27.2	31.6	189.8	27 %	151
Total proved	58.5	15.9	259.9	117.7	705.9	100 %	$ 2,528

Volume measurements:

MMBbls – million barrels for crude oil, condensate or NGLs	Bcf – billion cubic feet
MBoe – million barrels of oil equivalent	Bcfe – billion cubic feet equivalent

(1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2013 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, 2013. Prices were adjusted by lease for quality, transportation, fees, energy content and regional price differentials. For oil, the West Texas Intermediate posted price was used in the calculation and, after adjustments, a price of $99.65 per Bbl was used in computing the amounts above. For NGLs, a ratio was computed for each field of the NGLs realized price compared to the oil realized price. Then, this ratio was applied to the oil price using SEC guidance. The NGLs price of $35.21 per Bbl 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 $3.80 per Mcf was used in computing the amounts above. Such prices were held constant throughout the estimated lives of the reserves. Future production, development costs and ARO 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 Bbl 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):

	As of December 31, 2013
Present value of estimated future net revenues (PV-10)	$ 2,528
Present value of estimated ARO, discounted at 10%	(264)
PV-10 after ARO	2,264
Future income taxes, discounted at 10%	(589)
Standardized measure of discounted future net cash flows	$ 1,675

Changes in Proved Reserves

Our total proved reserves increased more than production, resulting in a slight net increase, and were 117.7 MMBoe (705.9 Bcfe) at December 31, 2013 compared to 117.5 MMBoe (705.1 Bcfe) at December 31, 2012. The change between periods is primarily as a result of extensions and discoveries of 20.2 MMBoe (121.0 Bcfe) due to the completion of eight successful exploratory wells (gross), utilizing 40 acre down-spacing onshore and joint interest activity. The extensions and discoveries were primarily in the Spraberry field (Yellow Rose) (12.6 MMBoe /75.4 Bcfe), the Ship Shoal 349/359 field (Mahogany) (4.2MMBoe/25.3 Bcfe) and the Mississippi Canyon 698 field (Big Bend) (1.9MMBoe/11.5 Bcfe). For the Spraberry field (Yellow Rose), the increase in proved reserves was primarily due to six exploration wells being completed, further development of the field from 40 acre down-spacing, movement of reserves from possible reserves to proved due to drilling activity by us and others and purchase of additional acreage in the field. For the Ship Shoal 349/359 field, the increase in proved reserves was from the successful drilling and completion of an exploratory well. The increase at the Mississippi Canyon 698 field was due to a successful exploration well. Estimated proved reserves also increased from the acquisition of Callon Properties discussed in Item 1, Business, which added 2.1 MMBoe (12.7 Bfe). Reserves decreased from revisions of previous estimates by 3.8 MMBoe (22.8 Bcfe) primarily at our Spraberry field (Yellow Rose) (4.9 MMBoe/29.6 Bcfe) and our High Island 21/22 field (2.3 MBoe/13.9 Bcfe) our due to performance, partially offset by increases due to price changes (1.9 MBoe/11.3 Bcfe). The sale of interests in three fields resulted in a decrease of 0.5 MMBoe (3.2 Bcfe). Decreases due to production were 18.0 MMBoe (107.9 Bcfe). See Development of Proved Undeveloped Reserves below for a table reconciling the change in proved undeveloped reserves during 2013. See Financial Statements – Note 21 – Supplemental Oil and Gas Disclosures under Part II, Item 8 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, 2013 included in this Form 10-K was prepared 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 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 25 years and a member of the Society of Petroleum Engineers for over 29 years. He has over 36 years total experience in the oil and gas industry, with over 22 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 oil and natural gas; and
- the judgment of the persons preparing the estimates.

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

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 Bbl to Mcfe using an energy-equivalent ratio of six Mcf to one Bbl of oil, condensate or NGLs. This energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for 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, 2013 were estimated at $910.0 million.

The following table presents our PUDs by field (in MMBoe):

	As of December 31,		
	2013	2012	2011
Ship Shoal 349 (Mahogany)	1.3	4.8	16.6
Mississippi Canyon 243 (Matterhorn)	1.3	2.1	3.1
Viosca Knoll 823 (Virgo)	1.4	1.4	1.4
Spraberry (Yellow Rose)	25.7	19.6	19.4
Mississippi Canyon 698 (Big Bend)	1.9	—	—
High Island 22	—	2.7	—
Total	31.6	30.6	40.5

The following table presents a reconciliation of our PUDs (in MMBoe):

	2013	2012
Proved undeveloped reserves – beginning of year	30.6	40.5
Reductions:		
Ship Shoal 349 (Mahogany)	(4.8)	(11.8)
Mississippi Canyon 243 (Matterhorn)	(0.7)	(1.6)
High Island 21/22	(2.7)	—
Spraberry (Yellow Rose) drilling, completions and technical	(4.6)	(9.7)
Spraberry (Yellow Rose) well performance	(1.5)	(0.2)
Subtotal – reductions	(14.3)	(23.3)
Balance after reductions	16.3	17.2
Additions:		
Ship Shoal 349 (Mahogany)	1.3	—
Mississippi Canyon 698 (Big Bend)	1.9	—
High Island 21/22	—	2.7
Spraberry (Yellow Rose) – well additions and other	7.9	10.0
Spraberry (Yellow Rose) – 40 acre down-spacing in 2013	4.2	—
Other changes	—	0.7
Subtotal —additions	15.3	13.4
Proved undeveloped reserves – end of year	31.6	30.6

Volume measurements:
MMBoe – million barrels of oil equivalent

Activity related to PUDs in 2013:

- During 2013, we drilled numerous development wells that converted PUDs to proved developed reserves ("PDs") and spent $270.4 million on development of PUDs. Activity in 2013 allowed conversion of approximately 47% of the PUDs existing at December 31, 2012 to PD's as of December 31, 2013.
- At our Ship Shoal 349/359 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 PDs 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 PDs. 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 PDs. 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 PDs. Subsequently, these PDs 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.

Activity related to PUDs in 2012:

- During 2012, we drilled numerous development wells that converted PUDs to PDs and spent $263.6 million on development of PUDs. Activity in 2012 allowed conversion of approximately 58% of the PUDs existing at December 31, 2011 to PD's as of December 31, 2012.
- At our Ship Shoal 349/359 field (Mahogany), we completed one well, (SS 359 A5 ST) and two additional wells were side tracked. As of December 31, 2012, we were in the process of completing the SS 359 A9 ST well, which moved additional reserves from PUDs to PDs.
- We completed one well (MC 243 A4 ST) at Mississippi Canyon 243 field (Matterhorn) in 2012.
- At our Spraberry field (Yellow Rose), we completed 53 development wells and 11 exploration wells. One of the wells completed was a horizontal well and two other horizontal wells reached target depth in 2012, which proved the concept and allowed additional horizontal PUD locations to be booked. Additionally, wells completed in 2011 and 2012 proved that the concept of down spacing to 40-acres was viable in a portion of the field, allowing the conversion of certain unproven locations to PUDs in 2012.
- In the High Island 21/22 field, a field study demonstrated that additional reserves could be recovered by drilling a replacement for a well that had experienced a mechanical failure. This allowed unproved reserves in 2011 to be reclassified as proved reserves in 2012.

See Business under Part I, Item 1, Our Fields in Item 2 above and Financial Statements – Note 2 – Acquisitions and Divestitures under Part II, Item 8 in this Form 10-K for additional information on the Spraberry, Ship Shoal 349/359, Mississippi Canyon 243 and Viosca Knoll 823 fields.

We believe that we will be able to develop all but 1.3 MMBoe of the reserves classified as PUDs, out of a total of 31.6 MMBoe classified as PUDs at December 31, 2013, 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. These PUDs were originally recorded in our reserves as of December 31, 2010. The development of the 1.3 MMBoe of 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 2016.

Our capital budget for 2014 for development is $233.0 million, split 76% offshore and 24% onshore. The capital allocated to our development activities will assist us in converting the PUDs to PDs.

Acreage

The following summarizes our leasehold at December 31, 2013. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	553,868	355,561	88,306	88,306	642,174	443,867
Deepwater	137,043	65,987	354,780	227,685	491,823	293,672
Total Offshore	690,911	421,548	443,086	315,991	1,133,997	737,539
Onshore	28,186	24,561	186,244	158,310	214,430	182,871
Total	719,097	446,109	629,330	474,301	1,348,427	920,410

Approximately 57% of our total net offshore acreage is developed and approximately 13% of our total net onshore 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, 78,113 net acres (25%) of the total 315,991 net undeveloped offshore acres could expire in 2014, 57,166 net acres (18%) could expire in 2015, 33,228 net acres (11%) could expire in 2016, 80,332 net acres (25%) could expire in 2017, and 67,152 net acres (21%) could expire in 2018 and beyond. For the onshore undeveloped leasehold, our rights to approximately 146,436 net acres of the total 158,310 net undeveloped onshore acres (93%) could expire in 2014 without additional drilling, 9,662 net acres (6%) could expire in 2015 and 2,212 net acres (1%) could expire in 2016. There are 141,109 net acres of the undeveloped onshore leasehold that can be extended by drilling two additional wells in 2014 and further extended by additional operations or production in future years. In making decisions regarding drilling and operations activity for 2014 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 49,387 net acres (6%) from December 31, 2012 and our net onshore acreage decreased 1,493 net acres (1%) from December 31, 2012. The decrease in our net offshore acreage was primarily due to certain offshore leases that terminated, partially offset by acreage added from the Callon Properties acquisition and other offshore property interests acquired through purchase.

Production

For the years 2013, 2012 and 2011, our net daily production averaged 295.7 MMcfe, 280.9 MMcfe and 278.2 MMcfe, respectively. Production increased in 2013 from 2012 and in 2012 from 2011 primarily due to acquisitions completed in 2012 and 2011 and increases in the Ship Shoal 349 field attributable to development activities, partially offset by decreases related to storms, pipeline shutdowns and natural reservoir declines.

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,		
	2013	2012	2011
Net sales:			
Oil (MBbls)	7,018	6,033	6,073
NGLs (MBbls)	2,091	2,129	1,892
Natural gas (MMcf)	53,257	53,825	53,743
Total oil equivalent (MBoe)	17,986	17,133	16,921
Total natural gas equivalent (MMcfe)	107,915	102,800	101,528

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 Spraberry field (Yellow Rose) and Ship Shoal 349/359 field (Mahogany) over the past three fiscal years, each of 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 of 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, 2013 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		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	93	79	88	68	181	147
Non-operated	21	6	37	11	58	17

	114	85	125	79	239	164

Onshore Wells

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	215	214	4	4	219	218
Non-operated	5	2	—	—	5	2
	220	216	4	4	224	220

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All Productive Wells (1)

	Oil Wells (1)		Gas Wells (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	308	293	92	72	400	365
Non-operated	26	8	37	11	63	19
	334	301	129	83	463	384

(1) Includes five gross (3.2 net) oil wells and seven gross (4.6 net) gas wells with multiple completions.

Drilling Activity

As presented in the tables below, our drilling activity decreased in 2013 compared to 2012 in our onshore operations. In 2013, we increased the onshore-horizontal drilling activity compared to 2012, which take longer to drill and are more expensive on a per well basis compared to vertical wells. Our onshore drilling activity is primarily in the Spraberry field, which was acquired by acquisition in May 2011, coupled with additional leasehold interests acquired in 2011 and 2013.

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

Development Drilling

The following table sets forth information related to our development wells drilled over the past three years.

	Year Ended December 31,		
	2013	2012	2011
Gross Wells:			
Productive:			
Offshore	4	3	5
Onshore	33	53	27
Non-productive:			
Offshore	—	—	—
Onshore	—	—	—
	37	56	32
Net Wells:			
Productive:			
Offshore	4.0	3.0	4.5
Onshore	32.9	52.8	27.0
Non-productive:			
Offshore	—	—	—
Onshore	—	—	—
	36.9	55.8	31.5

Our success rates related to our gross development wells drilled during 2013, 2012 and 2011 were 100%, 100% and 100%, respectively.

Exploration Drilling

The following table sets forth information related to our exploration drilling over the past three years.

	Year Ended December 31,		
	2013	2012	2011
Gross Wells:			
Productive:			
Offshore	1	1	3
Onshore	7	24	12
Non-productive:			
Offshore	1	1	—
Onshore	—	—	1
	9	26	16
Net Wells:			
Productive:			
Offshore	1.0	0.3	2.4
Onshore	6.9	20.8	7.6
Non-productive:			
Offshore	1.0	0.4	—
Onshore	—	—	0.7
	8.9	21.5	10.7

Our success rates related to our gross exploration wells drilled during 2013, 2012 and 2011 were 89%, 96% and 94%, respectively.

Recent Drilling Activity

The following table sets forth 2014 drilling activity to February 15, 2014.

	January 1, 2014 to February 15, 2014	
	Development	Exploration
Gross Wells:		
Productive:		
Offshore	—	1
Onshore	2	3
Non-productive:		
Offshore	—	—
Onshore	—	—