W&T OFFSHORE INC
Form 10-K
March 01, 2010
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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, 2009

or

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

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

Texas	**72-1121985**
(State of incorporation)	**(IRS Employer Identification Number)**
Nine Greenway Plaza, Suite 300	
Houston, Texas	**77046-0908**
(Address of principal executive offices)	**(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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

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

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

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

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

The aggregate market value of the registrant s common stock held by non-affiliates was approximately $328,938,998 based on the closing sale price of $9.74 per share as reported by the New York Stock Exchange on June 30, 2009.

The number of shares of the registrant s common stock outstanding on February 24, 2010 was 74,675,491.

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.

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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, that involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Certain factors that may affect our financial condition and results of operations are discussed in Item 1A Risk Factors and 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). We assume no obligation, nor do we intend, to update these forward-looking statements. 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.

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PART I

Item 1. ***Business***

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. We are an independent oil and natural gas producer, active in the acquisition, exploitation, exploration and development of oil and natural gas properties in the Gulf of Mexico, 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 develop and exploit 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. We have interests in leases covering approximately 0.9 million gross acres (0.6 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. Approximately 79% of our total gross acreage is held-by-production.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc., our independent petroleum consultant, our total proved reserves at December 31, 2009 were 371.0 Bcfe. We calculate that our total proved reserves had a present value of estimated future net revenues discounted at 10%, after considering future cash outflows related to asset retirement obligations and without deducting any future income taxes (PV-10), of approximately $890.0 million and a standardized measure of discounted future cash flows of approximately $660.4 million as of December 31, 2009. Approximately 76% of our reserves were classified as proved developed and 24% were classified as proved undeveloped. Classified by product, 45% of our reserves were natural gas and 55% were oil and natural gas liquids, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. For additional information about our proved reserves and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows, see Item 2 *Properties* *Proved Reserves*.

We seek to increase our reserves through acquisitions and drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to add reserves post-acquisition. Our acquisition team continues to work diligently to find properties that fit our profile and that we believe will add strategic and financial value to our company.

On December 21, 2007, we entered into an agreement with Apache Corporation (Apache) to acquire its interest in Ship Shoal 349 field for $116.6 million in cash. This field is located off the coast of Louisiana and covers two federal offshore lease blocks, Ship Shoal blocks 349 and 359. The transaction closed on January 29, 2008, with an effective date of January 1, 2008. The acquisition increased our working interest in this field to 100% from approximately 59%, and the estimated proved oil and natural gas reserves acquired were 60.5 Bcfe. This acquisition was funded with cash on hand. For additional details about this transaction, refer to Note 4 to our consolidated financial statements.

In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. In connection with these transactions, we reduced our asset retirement obligations by approximately $128.5 million and we received proceeds of approximately $32.2 million.

For the year ended December 31, 2009, our capital expenditures for oil and natural gas properties and equipment of $276.1 million included $90.6 million for exploration activities, $162.1 for development activities and $23.4 million for seismic, capitalized interest and other leasehold costs. We participated in the drilling of 10

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exploratory wells and three development wells, of which 12 were on the conventional shelf and one was on the deep shelf. Eight of the 10 exploration wells and two of the three development wells were successful. We operate five of the eight successful exploratory wells. During the three-year period ended December 31, 2009, we participated in the drilling of 41 exploratory wells, of which 32 were successful (which we define as completed or planned for completion). For a more detailed discussion of our drilling activity and capital expenditures, see Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital expenditures.*

We participated in bidding for Gulf of Mexico leases on the outer continental shelf (OCS) at the March 2009 OCS Lease Sale 208 conducted by the U.S. government through the Minerals Management Service (MMS). The MMS awarded us leases covering two OCS blocks located on the conventional shelf in the central Gulf of Mexico for a total lease bonus of approximately $0.4 million. We also participated in OCS Lease Sale 210 in August 2009 and we were awarded one lease for a lease bonus of approximately $0.3 million.

Our total capital expenditure budget for 2010 is $450 million. We anticipate fully funding our 2010 capital budget with internally generated cash flow and cash on hand. The budget includes seven conventional shelf exploration wells and other capital items such as well recompletions, facilities capital, seismic and leasehold items. At this time, we anticipate these capital expenditures will cost approximately $150 million. The balance of the $450 million budget will be allocated to acquisitions, additional drilling opportunities from the company s prospect inventory and/or new joint ventures offshore (on the shelf and in the deepwater) and onshore. Our 2010 capital budget is subject to change as conditions warrant. We are determined to remain as flexible as possible and believe this strategy holds the best promise for value creation and growth.

Business Strategy

We plan to continue to acquire and exploit oil and natural gas reserves on the OCS, the area of our historical success, or in other areas outside of the Gulf of Mexico that are compatible with our technical expertise and could yield rates of return sufficient to remain competitive in our industry. 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 turmoil, we also believe that other less well-capitalized producers may seek buyers for their properties, which could create opportunities for us.

We believe a significant portion of our 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 can be 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.

We believe our financial approach has contributed to our success and has positioned us to capitalize on new opportunities. Historically, we have limited our annual capital spending for exploration, exploitation and development activities to net cash provided by operating activities, and we have used capacity under our credit agreement for acquisitions and to balance working capital fluctuations. In 2010, we expect to fund our capital expenditures with internally generated cash flow and cash on hand.

Competition

The oil and natural gas industry is highly competitive. We currently operate almost exclusively in the Gulf of Mexico area and compete for the acquisition of oil and natural gas properties primarily on the basis of the price to be paid 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

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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 Item 1A *Risk Factors.*

Oil and Natural Gas Marketing and Delivery Commitments

We sell our oil 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 2009 we sold over 10% of our production to each of Shell Trading (US) Co., J.P. Morgan Ventures Energy Corp. and Chevron Corp. See *Concentration of Credit Risk* in Note 1 to our consolidated financial statements for additional information about our sales to these customers. Due to the nature of oil and natural gas markets and because oil and natural gas are freely traded commodities and there are numerous purchasers in the Gulf of Mexico, we do not believe the loss of a single purchaser or a few purchasers would materially affect our ability to sell our production.

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 natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

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.

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

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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 Outer Continental Shelf Lands Act (OCSLA), which is administered by the MMS 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 MMS 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 August 2005, Congress enacted the Energy Policy Act of 2005 (EPAct 2005). Among other matters, EPAct 2005 amends the NGA to make it unlawful for any entity, including otherwise non-jurisdictional producers such as W&T, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC s rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1 million per day per violation. The new anti-manipulation rule applies not only to activities that relate to intrastate or other non-jurisdictional sales or gathering, but also to activities of otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. (This now includes the annual reporting requirements under Order 704 described below). It therefore reflects a significant expansion of the FERC s enforcement authority.

In December 2007, the FERC issued rules (Order 704) requiring that any market participant, including a producer such as W&T, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus 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, MMS 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 natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids 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. 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 it affects 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 operations are conducted on federal oil and natural gas leases, which are administered by the MMS pursuant to the OCSLA. These leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed MMS regulations and orders that are subject to interpretation and change by the MMS. The MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures and pipelines.

To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees have substantial net worth 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. We are currently exempt from supplemental bonding requirements by the MMS. Under some circumstances, the MMS 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.

The MMS also 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 MMS.

Environmental regulations. 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 pollution, such as closure of inactive pits and 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 are significant costs to us. 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.

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Recent past hurricanes have significantly impacted oil and gas operations on the OCS. The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The MMS continues 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 MMS has 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 MMS for the 2010 hurricane season. These new requirements could increase our operating costs.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. However, environmental laws and regulations have been subject to frequent changes over the years and the imposition of more stringent requirements could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

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 oil or 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.

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.

Our operations are also subject to the Clean Air Act, as amended, (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. 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.

Past scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to the warming of the earth s atmosphere and causing physical environmental effects. In response to such studies, the U.S. Environmental Protection Agency (EPA) is considering regulations and the U.S. Congress is considering legislation to reduce emissions of greenhouse gases.

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On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allow the EPA to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse emissions from specified large greenhouse gases emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouses gases associated with our operations or could adversely affect demand of the oil and natural gas we produce.

Also on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions, and President Obama has indicated his support of legislation to reduce greenhouse emissions through an emission allowance system. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas that we produce.

The Federal Water Pollution Control Act of 1972, as amended, (the Clean Water Act) imposes restrictions and controls on the discharge of oil, produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The Clean Water Act, the Oil Pollution Act of 1990 (OPA90) and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act, OPA90, and state statutes enacted to control water pollution.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. The Safe Drinking Water Act of 1974, as amended, established a regulatory framework for underground injection. Hazardous waste injection well operations are strictly controlled and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In Louisiana and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate less than five permitted underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement actions. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

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Executive Order 13158, issued on May 26, 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 address the reduction of potential taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species). The MMS also issues numerous NTLs 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 officially been 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 might be required.

Our oil and natural gas operations include a production platform in the Gulf of Mexico located in a National Marine Sanctuary. As a result, we are subject to additional federal regulation, including 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 Endangered Species 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.

Naturally Occurring Radioactive Materials (NORM) contaminate minerals, minerals extraction and processing equipment used in the oil and natural gas industry. The resulting NORM waste 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 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.

We maintain insurance covering well control, property and hurricane damage, 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 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.

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Seasonality

For a discussion of seasonal changes that affect our business, see Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Inflation and Seasonality.*

Employees

As of December 31, 2009, we employed 286 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 items 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 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.

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 our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering 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 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 and natural gas production directly affects our revenues, profitability, access to capital and future rate of growth. Oil 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 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 and natural gas;
- the actions of the Organization of Petroleum Exporting Countries (OPEC);
- the price and quantity of imports of foreign oil, natural gas and liquefied natural gas;
- acts of war or terrorism;

economic conditions;

political conditions and events, including embargoes, affecting oil-producing activity;

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- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but may also reduce the amount of oil and natural gas that we can produce economically. The prices of oil and natural gas declined substantially during the second half of 2008 and natural gas prices have continued to be weak, especially compared to our costs per Mcfe, in the wake of decreased demand related to current economic conditions, increased supply and increased levels of natural gas in storage. 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 production, and to a lesser extent oil production, in the United States. The potential increases in natural gas supplies resulting from the large-scale development of these unconventional resource reserves could have an adverse impact on the price of natural gas. An environment of depressed oil and natural gas prices would materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

If oil 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. Primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008, we recorded a ceiling test impairment at December 31, 2008 of $1.2 billion. Additionally, we recorded a ceiling test impairment at March 31, 2009 of $218.9 million primarily as a result of a further decline in natural gas prices as of March 31, 2009. Declines in oil and natural gas prices after December 31, 2009 may require us to record an additional ceiling test impairment 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 and natural gas prices, we may also reduce our estimates of the reserves that may be economically recovered, which could reduce the total value of our proved reserves. See Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Impairment of oil and natural gas properties* and Note 1 to our consolidated financial statements for a discussion of the ceiling test.

We have been adversely affected by a recession in the United States and global economy.

The United States and other world economies are slowly recovering from a recession which began in 2008 and extended into 2009. Growth has resumed, but is modest. There are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future economic growth rate that is slower than what was experienced in recent years. In addition, more volatility may occur before a sustainable, yet lower, growth rate is achieved. A lower future economic growth rate will result in decreased demand growth for our oil and natural gas production as well as lower commodity prices, which will reduce our cash flows from operations and our profitability.

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

Borrowings under the revolving portion of our Third Amended and Restated Credit Agreement, as amended (the Credit Agreement), are currently limited to $405.5 million. Availability is determined periodically at the

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discretion of our lenders and is based in part on oil and natural gas prices and in part on our proved reserves. Substantially all of our oil and natural gas properties are pledged as collateral under the Credit Agreement. The Credit Agreement limits our ability to incur additional indebtedness based on specified financial covenants, ratios or other criteria. Lower oil and natural gas prices in the future could result in a reduction in 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 addition, pollution and environmental risks generally are not fully insurable. 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. We are also exposed to the possibility that we will be unable to buy insurance at any price or that if we do have a claim, the insurance companies will not pay our claim.

Included in lease operating expenses for the years ended December 31, 2009 and 2008 are hurricane remediation costs of $18.4 million and $17.7 million, respectively, related to Hurricanes Ike and Gustav that were either not yet approved by our insurance underwriters adjuster or were not covered by insurance. Included in lease operating expenses for the year ended December 31, 2007 is $18.5 million for hurricane remediation costs that were not covered by insurance, all of which related to Hurricanes Katrina and Rita in 2005.

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 increased insurance claims in recent years associated with hurricanes in the Gulf of Mexico, property damage and well control insurance coverage has become more limited and the cost of such coverage has increased. In June 2009, we renewed our insurance policies covering well control and hurricane damage at a cost of approximately $35 million. The current policy limits for well control and hurricane damage are $100 million and $85 million, respectively, with an additional $100 million for well control and hurricane damage on our Ship Shoal 349 field. A retention of $35 million per occurrence must be satisfied by us before we are indemnified for losses, and certain properties we have deemed as non-core are not covered for hurricane damage. However, properties representing approximately 89.3% of our PV-10 value of proved reserves at December 31, 2009 (before estimated asset retirement obligations) are covered under our new insurance policies for hurricane damage. Our insurers may not continue to offer this type and level of coverage to us, our costs may increase substantially as a result of increased premiums and the losses that may have been previously insured may no longer be insured. The occurrence of any or all of these could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have a claim, the insurance companies will not pay our claim.

Hedging transactions 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 hedging arrangements with respect to a portion of our expected production. For example, in the third quarter of 2009 we entered into commodity swap and option contracts relating to approximately 20 Bcfe of our anticipated production in 2010 to mitigate commodity price risk. We do not enter into derivative instruments for speculative trading purposes. While hedging transactions are intended to reduce the effects of volatile oil and natural gas prices, they may also limit future income if oil and natural gas

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prices were to rise substantially over the price established by the hedge. 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 hedge contracts fail to perform under the terms of the contracts.

We may be limited in our ability to book additional proved undeveloped reserves under the new SEC rules.

We have included in this report certain estimates of our proved reserves as of December 31, 2009 prepared consistent with our independent petroleum consultant s interpretation of the new SEC rules relating to modernizing reserve estimation and disclosure requirements for oil and natural gas companies. These new rules are effective for annual reporting periods ending on or after December 31, 2009. Included within these new SEC reserve rules is a general requirement that, subject to limited exceptions, 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 new 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, 2009, approximately 24% of our total proved reserves were undeveloped and approximately 32% 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.

While we have plans or are in the process of developing plans for exploiting and producing a majority of our proved reserves, 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 26% 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 may not be able to sustain production.

Our proved reserves have declined in each of the last three years. However, 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 development, exploration 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 and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

Relatively short production periods for our 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, exploitation 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

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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 vast majority of our current operations are in the Gulf of Mexico. Production from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the United States. Our independent petroleum consultant estimates that, on average, 52% of our total proved reserves are depleted within three years. As a result, our need to replace reserves 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 portion of their reserves outside the Gulf of Mexico area. We may not be able to develop, exploit, 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 operations, 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, the sale of production payments 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 and natural gas, and our success in developing and producing new reserves. We anticipate fully funding our 2010 capital expenditures with internally generated cash flow and cash on hand. 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 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 MMS 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.

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We conduct exploration, exploitation 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 limited 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 detect 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/or 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 almost exclusively in the Gulf of Mexico.

We are required to record a liability for the discounted present value of our asset retirement obligations to remove our platforms, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells, removing pipelines, removing and disposing of offshore platforms and site clean up. 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 are many years in the future, regulatory requirements may change and asset removal technologies and costs are constantly changing. As a result, we may make significant increases or decreases to our estimated asset retirement obligations in future periods. For example, in 2009 we increased our estimated asset retirement obligations by $77.3 million primarily relating to revised estimates for the dismantlement of two operated platforms that were toppled during Hurricane Ike and the plugging and abandonment of the associated wells. For additional information about our asset retirement obligations, see Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Asset retirement obligations.*

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. Accordingly, our estimate of future asset retirement obligations could differ dramatically from what we may ultimately incur as a result of damage from a hurricane.

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 will 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 development and exploitation 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;

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- 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;
- selection of technology; and
- the rate of production of the reserves.

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

Our development activities may be unsuccessful for many reasons, including adverse weather conditions (such as hurricanes and tropical storms in the Gulf of Mexico), cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not assure 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 business involves 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;

- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- train wrecks and derailment;
- abnormally pressured formations or rock compaction; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

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; and
- repairs required to resume operations.

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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, exploitation 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 affecting the Gulf of Mexico specifically.

The geographic concentration of our properties along the Texas and Louisiana Gulf Coast and adjacent waters on and beyond the outer continental shelf means that some or all of our properties could be affected by the same event should the Gulf of Mexico experience:

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

Because all our properties could experience the same condition 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. In 2009 and 2008, net production of approximately 8.7 Bcfe and 21.7 Bcfe, respectively, was deferred as a result of damage caused primarily by Hurricane Ike.

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 a continuing acquisition program, 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 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 not historically inspected every well, platform or pipeline. Even if we had 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.

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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, 2009. See Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Oil and natural gas reserve quantities* for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in Item 1 *Business* and Item 2 *Properties*.

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

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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 a property in which we own an interest or have operating rights and have what our geoscientists believe, based on available seismic and geological information, to be indications of economic quantities 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 you 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 and deep shelf formations may make it more difficult for us to sustain our historical rates of drilling success. As a result, there can be no assurance that we will find commercial quantities of oil and natural gas and, therefore, there can be 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. 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 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

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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, 2009, three fields, accounting for approximately 15 Bcfe (or 4%) of our total proved reserves, are tied back or are planned to be 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.

If third-party pipelines connected to our facilities become partially or fully unavailable to transport our natural gas or oil, our revenues 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. In 2009 and 2008, net production of approximately 8.7 Bcfe and 21.7 Bcfe, respectively, was deferred as a result of damage caused primarily by Hurricane Ike.

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 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

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and natural gas properties could be subject to eminent domain proceedings or other government takings for which we may not be adequately compensated. See Item 1 *Business Regulation* for a more detailed description 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;
- incurrence of investigatory or remedial obligations; and
- the imposition of injunctive relief.

In the past, we have been subject to investigation with respect to allegations that we did not comply with applicable environmental laws and regulations. Resolution of these matters has required management time and expense.

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 Item 1 *Business Regulation* 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.

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human 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. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse

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gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Also, on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas that we produce.

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 (including hurricanes), droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations. Please see *Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.*

We operate a production 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.

Our oil and natural gas operations include a production platform located in a National Marine Sanctuary in the Gulf of Mexico that is subject to special federal laws and 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.

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; W. Reid Lea, our Executive Vice President and Manager of Corporate Development; John D. Gibbons, our Senior Vice President, Chief Financial Officer and Chief Accounting Officer and Stephen L. Schroeder, our Senior Vice President and Chief Operating Officer, 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 Item 4A *Executive Officers of the Registrant* for more information regarding certain members of our management team.

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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 offshore 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 Texas, Louisiana, Alabama or other parts of the Gulf of Mexico, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

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

Substantially all of our accounts receivable result from oil 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 and natural gas prices can affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding 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.

Global financial markets and economic conditions have been distressed. We may be unable to obtain adequate funding under our current credit facility either because our lending counterparties may be unwilling or unable to meet their funding obligations or our borrowing base under the Credit Agreement is decreased as the result of lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason. For example, in April 2009, our lenders reduced the borrowing base under the Credit Agreement from $710.0 million to $405.5 million.

Due to these factors, we cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. 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 our debt. 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.

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If we do not generate enough cash flow from operations to satisfy 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.

However, 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 controls 39,234,187 shares of our common stock, representing approximately 52.5% of our voting interests as of February 24, 2010. As a result, Mr. Krohn has the ability to control the outcome of virtually all matters requiring shareholder 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 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 New York Stock Exchange (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 a majority of directors on the board who are independent from our principal shareholder.

Item 1B. ***Unresolved Staff Comments***

None.

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Item 2. ***Properties***

Substantially all of our fields are located in the Gulf of Mexico. These fields are found in water depths ranging from less than ten feet up to 4,200 feet. The reservoirs in our fields are generally characterized as having high porosity and permeability, which typically result in high production rates. The following describes our ten largest fields as of December 31, 2009, based on quantities of proved reserves on a natural gas equivalent basis. At December 31, 2009, these fields accounted for approximately 72% of our PV-10 value before estimated asset retirement obligations, or $803 million, and had proved reserves totaling 274.1 Bcfe.

Field Name	Field Category	Operator	Percent Natural Gas of Net Reserves	2009 Average Daily Equivalent Sales Rate (MMcfe/d) Gross	Net
Ship Shoal 349	Shelf	W&T	18%	16.8	14.0
Main Pass 108	Shelf	W&T	78%	66.7	37.1
Brazos A-133	Shelf	Apache	99%	39.4	8.2
West Delta 30	Shelf	W&T and Anglo-Suisse (1)	6%	3.1	2.6
Green Canyon 646	Deepwater	W&T	15%	7.6	4.4
East Cameron 321	Shelf	W&T	31%	24.4	20.3
Mobile 823	Deep shelf	ExxonMobil	84%	65.3	6.8
South Timbalier 228	Shelf	W&T	11%	7.3	6.1
Ship Shoal 208	Shelf	W&T	64%	8.3	4.5
Mustang Island 889	Shelf	Sabco	66%	2.5	1.0

(1) W&T operates all down hole operations.

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On December 31, 2009 we had one field 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). Below is a description of this field, Ship Shoal 349, which is located on the conventional shelf.

Ship Shoal 349 Field. 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 discovered the field in 1993. We initially acquired a 25% working interest in the field from BP 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 and we now own a 100% working interest in this field. Cumulative field production through 2009 is approximately 169 Bcfe gross. This field is a sub-salt development with five productive horizons below salt at depths ranging to 17,000 feet. As of December 31, 2009, 22 wells have been drilled, of which 13 have been successful. We are currently developing a reservoir simulation model in order to optimize future development opportunities. Total proved reserves associated with our interest in this field were 122 Bcfe at December 31, 2009.

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

	Year Ended December 31,		
	2009	2008	2007
Net sales:			
Natural gas (Bcf)	0.8	0.7	0.4
Oil (MMBbls)	0.7	0.7	0.3
Total natural gas and oil (Bcfe)	5.1	4.6	2.1
Average realized sales prices:			
Natural gas ($/Mcf)	$ 4.56	$ 10.80	$ 7.37
Oil ($/Bbl)	54.02	94.83	59.34
Natural gas equivalent ($/Mcfe)	8.33	15.05	9.47
Average per Mcfe ($/Mcfe):			
Production costs (1)	$ 2.43	$ 1.33	$ 1.40

(1) Includes lease operating expenses and gathering and transportation costs. The increase in 2009 production costs per Mcfe compared to 2008 primarily relates to higher insurance costs in 2009. In addition to our standard insurance policies for well control and hurricane damage, we have an additional $100 million of insurance for well control and hurricane damage on our Ship Shoal 349 field.

The following is a description of the remainder of our top ten properties, measured by proved reserves at December 31, 2009, of which seven are located on the conventional shelf, one is located in the deepwater and one is located on the deep shelf. We do not believe that individually any of these properties are of major significance (each has proved reserves which comprise less than 15% of the Company s total proved reserves, calculated on a natural gas equivalent basis).

Main Pass 108 Field. Main Pass 108 field consists of Main Pass blocks 94, 102, 106, 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. 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, 2009, 51 wells have been drilled in this field, of which 37 were successful. Cumulative field production through 2009 is approximately 330 Bcfe gross. During December 2009, production from this field, net to our interest, averaged 23.0 MMcf of natural gas per day and 1,193 Bbls of oil per day, or 30.2 MMcfe per day.

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Brazos A-133 Field. Brazos A-133 field is located 85 miles east of Corpus Christi, Texas in 200 feet of water. The field was discovered in 1978 by Cities Service Oil Company with production commencing in the same year. There are five active platforms, three of which are production platforms. Cumulative field production through 2009 is approximately 850 Bcfe gross from the Middle Miocene Tex W and Big Hum sections. The bulk of the production is from the Big Hum CM-7 sand, which is a 4-way closure downthrown to the Corsair Fault and bisected by antithetic faults. The top of the CM-7 sand is at a subsea depth of 12,000 feet. Since its discovery, 22 wells have been drilled, of which 17 were successful. We own a 25% working interest that was obtained through a transaction with Kerr-McGee. During December 2009, production from this field, net to our interest, averaged 6.7 MMcf of natural gas per day and 12 Bbls of oil per day, or 6.8 MMcfe per day.

West Delta 30 Field. West Delta 30 field is located approximately six miles off the coast of Louisiana in 40 feet of water. Our interests in this field are in West Delta Block 29, which straddles the eastern side of a major piercement salt dome with large accumulations of oil and natural gas sands found in traps along the salt flanks. In 1997, we entered into a farmout agreement with ChevronTexaco to further explore and develop potential reserves. Following a thorough 3-D seismic analysis, we have drilled a total of 17 exploration and development wells, all but one of which have been successful. Our working interests in these wells range from 37.5% to 100%. Cumulative field production through 2009 is approximately 700 Bcfe gross. During December 2009, production from this field, net to our interest, averaged 276 Bbls of oil per day, or 1.7 MMcfe per day.

Green Canyon 646 Field. Green Canyon 646 field is located approximately 150 miles south of New Orleans, Louisiana, in 4,200 feet of water. The discovery well, which we drilled to a total depth of 12,365 feet in January 2004, is a subsea well tied back to the Front Runner Spar located more than 20 miles away in Green Canyon 338. The field play consists of stacked sheet sands located on the flank of a salt dome between 10,500 and 12,000 feet. The well commenced production in September 2009. We own a 60% working interest in the field and are the operator of the field. Cumulative field production through 2009 is approximately two Bcfe gross. During December 2009, production from this field, net to our interest, averaged 1.7 MMcf of natural gas per day and 2,303 Bbls of oil per day, or 15.5 MMcfe per day.

East Cameron 321 Field. East Cameron 321 field is located approximately 97 miles off the Louisiana coastline in 225 feet of water. Two production facilities, the A and B platforms, are located on the block. This field has multiple sands that are productive in faulted, structural traps. As of December 31, 2009, 75 wells have been drilled of which 57 have been successful. Cumulative field production through 2009 is approximately 545 Bcfe gross. We own a 100% working interest in the field and are the operator of the field. During December 2009, production from this field, net to our interest, averaged 3.0 MMcf of natural gas per day and 1,958 Bbls of oil per day, or 14.8 MMcfe per day.

Mobile 823 Field. Mobile 823 field is located off the coast of Alabama in approximately 60 feet of water. It is a natural gas field comprised of two OCS blocks, Mobile Blocks 822 and 823. The field was discovered by Mobil Oil Corporation in 1983, with initial production commencing in 1991. We acquired our 12.5% working interest in 2003 from ConocoPhillips. ExxonMobil currently operates the majority of the field. We operate one well, a Miocene Luce sand discovery drilled in 2006. Production is primarily from the Jurassic Norphlet sandstone at 21,500 feet, with minor production from Miocene sands at 3,000 to 7,000 feet. The trapping mechanism is a combination structural and stratigraphic trap. Cumulative field production through 2009 is approximately 787 Bcfe gross from eleven productive wells. The field has one processing platform and three independent structures. During December 2009, production from this field, net to our interest, averaged 4.8 MMcf of natural gas per day and 178 Bbls of oil per day, or 5.9 MMcfe per day.

South Timbalier 228 Field. South Timbalier 228 field is located 50 miles off the coast of Louisiana in about 220 feet of water and includes South Timbalier blocks 229 and 230. The field was discovered in November 1994 by The Louisiana Land and Exploration Company. We acquired South Timbalier block 229 from Burlington Resources and became operator of the field in November 2002. We acquired South Timbalier block 230 in OCS Lease Sale 194, with an effective date of June 2005. We are a 100% working interest owner in this field. We

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have drilled six wells since becoming operator, all of which were successful. All of the producing sands are within the basal Nebraskan section. Cumulative production from this field through 2009 is approximately 43 Bcfe gross. During December 2009, production from this field, net to our interest, averaged 0.5 MMcf of natural gas per day and 852 Bbls of oil per day, or 5.6 MMcfe per day.

Ship Shoal 208 Field. Ship Shoal 208 field is located approximately 50 miles off the coast of Louisiana in 96 feet of water and includes Ship Shoal block 214. The discovery well for Ship Shoal block 214 was drilled by Kerr-McGee in 1961. This field covers the eastern side of a large piercement salt dome, which acts to trap significant accumulations of Upper Miocene and Pliocene-age oil and natural gas deposits. We own a 64.5% working interest in the field and are the operator of the field. Cumulative field production through 2009 is approximately 907 Bcfe. During December 2009, production from this field, net to our interest, averaged 3.7 MMcf of natural gas per day and 311 Bbls of oil per day, or 5.6 MMcfe per day.

Mustang Island 889 Field. Mustang Island 889 field is located approximately 20 miles southeast of Corpus Christi, Texas in 30 feet of water. The field was discovered by Shell in 1958. We have a 50% working interest in the F-1 well, which was drilled to a total depth of 13,500 feet in 2005 and was completed in the S Sand. Two additional pay sands are behind pipe. These Oligocene Frio sands are trapped in three-way structures upthrown to several down-to-the-basin growth faults. Minor faulting complicates the structures. Cumulative field production through 2009 is approximately 168 Bcfe. During December 2009, production from this field, net to our interest, averaged 0.6 MMcf of natural gas per day and 30 Bbls of oil per day, or 0.8 MMcfe per day.

Proved Reserves

In December 2008, the SEC adopted new rules related to modernizing reserve estimation and disclosure requirements for oil and natural gas companies, which became effective for annual reporting periods ending on or after December 31, 2009. The new rules permit the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of *proved reserves* which was changed to indicate, among other things, that commencing with year-end 2009 entities must use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than end-of-period prices, when estimating quantities of proved reserves. Similarly, beginning in the fourth quarter of 2009, the estimated future net revenues used to calculate the ceiling test are based on the 12-month average commodity price for each product. Also, because it is our policy to use end-of-period reserves in the determination of quarterly depletion, our depreciation, depletion, amortization and accretion (DD&A) expense for the fourth quarter of 2009 was calculated using proved reserves at December 31, 2009 that were determined in accordance with the new rules. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, 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.

Applying the new rules, our proved reserves at December 31, 2009 totaled 371.0 Bcfe. Approximately 76% of our reserves were classified as proved developed and 24% were classified as proved undeveloped. Classified by product, 45% of our reserves were natural gas and 55% were oil and natural gas liquids, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. Our proved reserves were estimated by our independent petroleum consultant, Netherland, Sewell & Associates, Inc. The scope and results of their procedures are summarized in a letter which is included as an exhibit to this Annual Report on Form 10-K.

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Our proved reserves as of December 31, 2009 are summarized below. These reserve amounts are consistent with filings we make with other federal agencies.

	As of December 31, 2009				
Classification of Proved Reserves	**Oil (MMBbls)**	**Gas (Bcf)**	**Total (Bcfe)**	**% of Total Proved**	**PV-10 (2) (In millions)**
Proved developed producing	12.7	86.6	162.5	44%	$ 304.0
Proved developed non-producing (1)	11.0	54.7	121.0	32%	279.2
Total proved developed	23.7	141.3	283.5	76%	583.2
Proved undeveloped	10.5	24.5	87.5	24%	306.8
Total proved	34.2	165.8	371.0	100%	$ 890.0

(1) Includes approximately 1.7 Bcfe of reserves with a PV-10 (before estimated asset retirement obligations) of $12.4 million that were shut-in at December 31, 2009 because of damage caused by Hurricane Ike in September 2008. We anticipate that the majority of these reserves will be reclassified to producing in the first half of 2010.

(2) Refer to footnote (3) under *Reserves Pricing Sensitivities* below for a reconciliation of PV-10 to the most comparable measure under generally accepted accounting principles (GAAP).

In accordance with guidelines established by the SEC, our proved reserves as of December 31, 2009 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 period January 2009 through December 2009. For oil and natural gas liquids, the average West Texas Intermediate posted price of $57.65 per barrel was adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the average Henry Hub spot price of $3.87 per MMBtu was adjusted by lease for energy content, transportation fees and regional price differentials. Such prices were held constant throughout the estimated lives of the reserves. Future production and development costs are based on year-end costs with no escalations. We refer to this estimate of our proved reserves as the SEC Case.

Changes in Proved Reserves

Our total proved reserves decreased 120.1 Bcfe to 371.0 Bcfe at December 31, 2009 from 491.1 Bcfe at December 31, 2008, primarily attributable to production of 94.8 Bcfe and divestitures of certain non-core oil and natural gas fields. In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. These dispositions collectively accounted for a 23.9 Bcfe reduction in total proved reserves. We also had negative revisions of 4.7 Bcfe due to performance. These decreases in reserves were partially offset by an increase in total proved reserves of 23.4 Bcfe, the majority of which is attributable to extensions and discoveries resulting from our participation in the drilling of eight successful exploratory wells in 2009, all of which were on the conventional shelf.

The remaining significant component of our decrease in total proved reserves from December 31, 2008 are revisions primarily from the adoption of the new SEC rules related to modernizing reserve estimation and disclosure requirements. The initial application of these rules resulted in the removal of 23.2 Bcfe of proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded, as required. In addition, positive revisions of 27.5 Bcfe that would have resulted from using end-of-period commodity prices as of December 31, 2009 ($76.00 per barrel for oil and natural gas liquids and $5.79 per MMBtu for natural gas) were offset by 25.1 Bcfe, the impact of which is attributable to the new requirement that oil and natural gas reserves are to be measured using the 12-month average commodity price for each product ($57.65 per barrel for oil and natural gas liquids and $3.87 per MMBtu for natural gas).

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Reserves Pricing Sensitivities

In addition to the SEC Case proved reserves, our independent petroleum consultant also prepared estimates of our year-end proved reserves using two alternative commodity price assumptions. The following table summarizes our total proved reserves as of December 31, 2009 under each of the three cases:

	Total Proved Reserves As of December 31, 2009			
Case	**Oil (MMBbls)**	**Gas (Bcf)**	**Total (Bcfe)**	**PV-10 (3) (In millions)**
SEC	34.2	165.8	371.0	$ 890.0
Flat (1)	35.8	181.1	396.0	1,578.5
NYMEX (2)	36.7	186.0	406.0	1,841.1

(1) The Flat Case is based on the posted spot prices as of December 31, 2009 for both oil and natural gas. For oil and natural gas liquids, the West Texas Intermediate posted price of $76.00 per barrel was adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the Henry Hub spot price of $5.79 per MMBtu was adjusted by lease for energy content, transportation fees and regional price differentials. Such prices were held constant throughout the estimated lives of the reserves. Future production and development costs are based on year-end costs with no escalations.

(2) The NYMEX Case is based on the applicable monthly forward closing prices on the New York Mercantile Exchange for oil and natural gas as of December 31, 2009. For oil and natural gas liquids, the price was based on a crude oil price which increased from $79.36 per Bbl to $101.92 per Bbl during the life of the reserves and was adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the price was based on a natural gas price which increased from $5.57 per MMBtu to $9.05 per MMBtu over the life of the properties and was adjusted by lease for energy content, transportation fees and regional price differentials. Future production and development costs are based on year-end costs with no escalations.

(3) We refer to PV-10 as the present value of estimated future net revenues before asset retirement obligations as calculated by our independent petroleum consultant, adjusted by the Company to include estimated asset retirement obligations discounted using a 10% annual discount rate. PV-10 is not a financial measure prescribed under GAAP; therefore, the following table reconciles our calculation of PV-10 under the SEC Case to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. There is no directly comparable GAAP measure for the Flat case PV-10 or the NYMEX case PV-10. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Management believes that PV-10 is relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. Further, professional analysts and sophisticated investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies reserves. Management also uses this pre-tax measure when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating us. PV-10 is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. The reconciliation of PV-10 to the standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves at December 31, 2009 for the SEC Case is as follows (in millions):

	At December 31, 2009 SEC Case
Present value of estimated future net revenues before asset retirement obligations (ARO)	$ 1,123.2
Present value of estimated ARO, discounted at 10%	(233.2)
Present value of estimated future net revenues (PV-10)	890.0

Future income taxes, discounted at 10%		(229.6)
Standardized measure of discounted future net cash flows	$	660.4

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The following table presents the reconciliation of PV-10 before ARO to PV-10 relating to our proved oil and natural gas reserves at December 31, 2009 for the Flat Case and the NYMEX Case (in millions):

	At December 31, 2009	
	Flat Case	NYMEX Case
PV-10 before ARO	$ 1,793.9	$ 2,047.8
Present value of estimated ARO, discounted at 10%	(215.4)	(206.7)
PV-10	$ 1,578.5	$ 1,841.1

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Our proved reserve information as of December 31, 2009 included in this Annual Report on Form 10-K was estimated by our independent petroleum consultant, Netherland, Sewell & Associates, Inc. (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 which is included as an exhibit to this Annual Report on 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 21 years and a member of the Society of Petroleum Engineers for over 25 years. He has over 32 years total experience in the oil and gas industry, with over 18 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.

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

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the judgment of the persons preparing the estimates.

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

Reporting of Oil and Natural Gas Production and Reserves

We produce natural gas liquids as part of the processing of our natural gas. The extraction of natural gas liquids in the processing of natural gas reduces the volume of natural gas available for sale. In our December 31, 2009 reserve report prepared by our independent petroleum consultant, natural gas liquids represented approximately 4.8% of our total proved reserves. Natural gas liquids are products sold by the gallon. Therefore, in reporting reserve and production amounts of natural gas liquids, we include this production in the oil category. Prices for natural gas liquids in 2009 were approximately 47% lower on average than prices for equivalent volumes of oil. We report our average oil prices realized after taking into account the effect of the lower prices received for sales of natural gas liquids. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of natural gas liquids.

Development of Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2009, as estimated by our independent petroleum consultant, were 87.5 Bcfe. Future development costs associated with our proved undeveloped reserves at December 31, 2009 totaled approximately $152 million, substantially all of which is expected to be spent after December 31, 2010. In 2009, we developed approximately 11% of our proved undeveloped reserves as of December 31, 2008, consisting of three gross (1.9 net) wells and the subsea tie-in of one gross (0.6 net) deepwater well at a net cost of approximately $104.5 million.

Only one of our proved undeveloped well locations remains undeveloped past 5 years from the date of initial recognition as proved undeveloped. Green Canyon 646 #1 sidetrack was initially booked in 2003. This proved undeveloped location is a sidetrack to a currently producing well, a subsea oil producer tied back to the Front Runner Spar, located over 20 miles from the well location. The capital cost for this tie-in was approximately $60 million. Due to the high development cost, the proved undeveloped location will utilize the existing well bore in order to sidetrack updip to the target location, which will only be drilled after substantial depletion of the producing well. As of December 31, 2009, proved undeveloped reserves associated with this location were 10.6 Bcfe.

Acreage

The following summarizes gross and net developed and undeveloped acreage at December 31, 2009. Net acreage is our percentage ownership of gross acreage. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	663,323	394,003	123,783	102,737	787,106	496,740
Deepwater	57,465	27,733	62,832	54,192	120,297	81,925
	720,788	421,736	186,615	156,929	907,403	578,665

Approximately 79% of our total gross acreage is held-by-production, which permits us to maintain all of our exploration, exploitation and development rights (including deep rights below currently producing zones) to the leased area as long as production continues. We have the right to propose future exploration and development projects, including deep exploration projects, on the majority of our acreage.

Approximately 21% of our total gross acreage is undeveloped leasehold. Of our 186,615 total gross undeveloped acres, our rights to approximately 27% could expire in 2010, 7% in 2011, 1% in 2012, 16% in 2013

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and 49% in 2014 and beyond, if not extended by exploration and production activities prior to the applicable lease expiration dates. Our drilling activity for 2010 will give consideration to our undeveloped leasehold that may expire in 2010 in order to retain the opportunity to exploit such acreage, based on the appropriate technical criteria, before expiration of the lease.

In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. In connection with the sale of these properties, we retained the right to participate in certain identified drilling opportunities that could be proposed by the new owners. As a result of the sale of these properties and lease expirations, our total gross and net acreage decreased 37% and 30%, respectively, as of December 31, 2009 from year-end 2008.

Production

During 2009, our net production averaged approximately 259.7 MMcfe per day. Approximately 8.7 Bcfe of net production was deferred during 2009 as a result of damage caused primarily by Hurricane Ike during the third quarter of 2008.

Production History

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

	Year Ended December 31,		
	2009	2008	2007
Net sales:			
Natural gas (Bcf)	51.6	56.1	76.7
Oil (MMBbls)	7.2	7.0	8.3
Total natural gas and oil (Bcfe)	94.8	97.9	126.5

Refer to the descriptions of our ten largest fields earlier in Item 2 *Properties* for historical information about our produced oil and natural gas volumes from our Ship Shoal 349 field over the past three fiscal years, which is the only field at December 31, 2009 with proved reserves which comprise 15% or more of the Company s total proved reserves. Also refer to Item 6 *Selected Financial Data Historical Reserve and Operating Information* for additional historical operating data.

Productive Wells

The following presents our ownership interest at December 31, 2009 in our productive oil and natural gas wells, including wells that were temporarily shut-in on that date primarily because of Hurricane Ike in 2008. A net well is our percentage working interest of a gross well.

	Oil Wells (1)		Gas Wells (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	111	93.7	112	99.5	223	193.2
Non-operated	57	20.8	107	13.2	164	34.0
	168	114.5	219	112.7	387	227.2

(1) Includes 7 gross (4.5 net) oil wells and 11 gross (6.1 net) gas wells with multiple completions.

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Our ownership in wells that were temporarily shut-in at December 31, 2009 primarily because of Hurricane Ike in 2008 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	6	2.6	8	5.7	14	8.3
Non-operated	13	4.3	11	1.8	24	6.1
	19	6.9	19	7.5	38	14.4

Drilling Activity

During 2009, we participated in the drilling of 10 gross exploratory wells and three gross development wells, of which 12 were on the conventional shelf and one was on the deep shelf. Eight of the 10 exploration wells and two of the three development wells were successful. We operate five of the eight successful exploratory wells.

The level of our investment in oil and gas properties changes from time to time depending on numerous factors, including the prices of oil and natural gas, acquisition opportunities and the results of our exploration and development activities. For the year ended December 31, 2009, our capital expenditures for oil and natural gas properties and equipment of $276.1 million included $90.6 million for exploration activities, $162.1 million for development activities and $23.4 million for seismic, capitalized interest and other leasehold costs.

Development Drilling

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

	Year Ended December 31,		
	2009	2008	2007
Gross Wells:			
Productive	2	2	2
Non-productive	1		
	3	2	2
Net Wells:			
Productive	1.7	1.7	1.1
Non-productive	0.5		
	2.2	1.7	1.1

Our success rates related to our gross development wells drilled during the years ended December 31, 2009, 2008 and 2007 were 67%, 100% and 100%, respectively.

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Exploration Drilling

The following sets forth information relating to our exploration drilling over the past three fiscal years.

	Year Ended December 31, 2009	2008	2007
Gross Wells:			
Productive	8	18	6
Non-productive	2	6	1
	10	24	7
Net Wells:			
Productive	5.9	12.3	4.2
Non-productive	1.3	4.4	0.7
	7.2	16.7	4.9

Our success rates related to our gross exploration wells drilled during the years ended December 31, 2009, 2008 and 2007 were 80%, 75% and 86%, respectively.

Current Drilling Activity

During the period beginning January 1, 2010 and ending February 24, 2010, we participated in the drilling of one gross (1.0 net) unsuccessful exploratory well. We were in the process of drilling one gross (1.0 net) exploratory well as of February 24, 2010.

Item 3. *Legal Proceedings*

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

Item 4. *Reserved*

Item 4A. *Executive Officers of the Registrant*

The following lists our executive officers:

Name	Age	Position
Tracy W. Krohn	55	Founder, Chairman, Director and Chief Executive Officer
J.F. Freel	97	Founder, Chairman Emeritus, Director and Secretary
Jamie L. Vazquez	49	President
W. Reid Lea	51	Executive Vice President and Manager of Corporate Development
John D. Gibbons	56	Senior Vice President, Chief Financial Officer and Chief Accounting Officer

Stephen L. Schroeder	47	Senior Vice President and Chief Operating Officer

Tracy W. Krohn has served as Chief Executive Officer since he founded the Company in 1983 and as Chairman since 2004. He also served as President of the Company until September 2008. Mr. Krohn s mother is married to Mr. J.F. Freel.

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J.F. Freel has served as a director since our founding in 1983 and Secretary of the Company since 1984. Mr. Freel is married to Mr. Krohn s mother.

Jamie L. Vazquez joined the Company in 1998 as Manager of Land and in 2003 she was named Vice President of Land. In September 2008, Ms. Vazquez was appointed President of the Company.

W. Reid Lea has served as the Company s Executive Vice President and Manager of Corporate Development since September 2005. He joined the Company as Vice President of Finance in 1999 and served as our Chief Financial Officer from 2000 until September 2005.

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

Stephen L. Schroeder joined the Company in 1998 and served as Production Manager from 1999 until 2005. In 2005, Mr. Schroeder was named Vice President of Production and in July 2006 he was named Senior Vice President and Chief Operating Officer.

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PART II

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

Our common stock is listed and principally traded on the New York Stock Exchange under the symbol WTI. The following sets forth, for each of the periods indicated, the high and low sales price of our common stock as reported on the New York Stock Exchange.

	High	Low
2008		
First Quarter	$ 39.39	$ 26.41
Second Quarter	59.99	33.40
Third Quarter	59.99	25.20
Fourth Quarter	27.01	9.99
2009		
First Quarter	17.30	4.94
Second Quarter	12.10	5.80
Third Quarter	12.88	7.70
Fourth Quarter	14.87	9.78

As of February 24, 2010, there were 326 registered holders of our common stock.

Dividends

Under the Credit Agreement, we are allowed to pay annual dividends if we are not in default. On July 24, 2008, certain amendments were made to the Credit Agreement, including increasing the annual amount available for dividend distribution or share repurchases to $60.0 million per year from $30.0 million per year. In addition, the indenture governing the Notes contains restrictions on the payment of dividends unless we meet the restricted payment tests in the indenture. See Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources* and Note 6 to our consolidated financial statements for more information regarding our Credit Agreement and the indenture governing the Notes.

The following reflects the frequency and amounts of all cash dividends declared during the two most recent fiscal years (in thousands, except per share data):

	Aggregate Dividends on Common Stock	Dividend per Share of Common Stock
2008		
First Quarter	$ 2,291	$ 0.03
Second Quarter	2,291	0.03
Third Quarter	2,291	0.03
Fourth Quarter (1)	20,840	0.27
2009		
First Quarter	2,289	0.03
Second Quarter	2,292	0.03
Third Quarter	2,292	0.03
Fourth Quarter	2,285	0.03

(1) Consists of a special cash dividend of approximately $0.2729 per common share.

With the exception of any special cash dividends, we currently expect that comparable cash dividends will continue to be paid in the future, subject to periodic reviews of the Company s performance by our board of

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directors. On February 24, 2010, our board of directors declared a cash dividend of $0.03 per common share, payable on March 27, 2010 to shareholders of record on March 12, 2010.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 in our common stock on the date of our initial public offering (January 28, 2005) and the reinvestment of all dividends thereafter. The information contained in the graph below is furnished and not filed, and is not incorporated by reference into any document that incorporates this Annual Report on Form 10-K by reference.

Our peer group is comprised of ATP Oil & Gas Corp., Cabot Oil & Gas Corp., Comstock Resources, Inc., Forest Oil Corp., Mariner Energy, Inc., McMoRan Exploration Co., Newfield Exploration Co., Noble Energy, Inc., Plains Exploration & Production Co., Quicksilver Resources Inc., St. Mary Land & Exploration Co., Stone Energy Corp., Venoco, Inc., and Whiting Petroleum Corp.

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Issuer Purchases of Equity Securities

In March 2009, we announced by press release a $25 million stock repurchase program, which expired on December 31, 2009. Under the program, shares could be purchased from time to time at prevailing prices in the open market, in block transactions, in privately negotiated transactions or accelerated share repurchase programs through December 31, 2009, in accordance with Rule 10b-18 under the Exchange Act. During the quarter ended December 31, 2009, we purchased 1,439,687 shares of our common stock for approximately $14.9 million in the open market in accordance with the repurchase program, as set forth in the following table (in millions, except share and per share data):

Period		Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (1)
November 1, 2009	November 30, 2009	1,006,372	$ 10.32	1,006,372	$ 5.4
December 1, 2009	December 31, 2009	433,315	10.45	433,315	

(1) During the year ended December 31, 2009, we purchased a total of 2,869,173 shares of our common stock for approximately $24.2 million in the open market in accordance with the repurchase program. Repurchases were funded with cash on hand.

The following table sets forth information about shares delivered by employees during the quarter ended December 31, 2009 to satisfy tax withholding obligations on the vesting of restricted shares.

Period		Total Number of Shares Delivered	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
December 1, 2009	December 31, 2009	182,445	$ 11.39	N/A	N/A

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Item 6. ***Selected Financial Data***

SELECTED HISTORICAL FINANCIAL INFORMATION

The selected historical financial information set forth below should be read in conjunction with Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations* and with our consolidated financial statements and notes to those financial statements included elsewhere in this report.

	Year Ended December 31,				
	2009 (1)	2008	2007	2006 (2)	2005
	(Dollars in thousands, except per share data)				
Consolidated Statement of Income (Loss) Information:					
Revenues:					
Natural gas	$ 204,758	$ 527,352	$ 552,687	$ 427,839	$ 384,985
Oil	400,658	688,097	560,940	372,509	199,579
Other	5,580	160	122	118	572
Total revenues	610,996	1,215,609	1,113,749	800,466	585,136
Operating costs and expenses:					
Lease operating expenses (3)	203,922	229,747	234,758	113,993	75,732
Production taxes	1,544	8,827	5,921	1,556	712
Gathering and transportation	13,619	15,957	15,526	16,141	11,990
Depreciation, depletion and amortization	308,076	482,464	510,903	325,131	174,771
Asset retirement obligation accretion	34,461	39,312	22,007	12,496	9,062
Impairment of oil and natural gas properties (4)	218,871	1,182,758			
General and administrative expenses (5)(6)	42,990	47,225	38,853	37,778	24,444
Derivative loss (gain) (7)	7,372	16,464	36,532	(24,244)	
Total costs and expenses	830,855	2,022,754	864,500	482,851	296,711
Operating income (loss)	(219,859)	(807,145)	249,249	317,615	288,425
Interest expense, net of amounts capitalized	40,087	34,709	37,088	17,180	1,145
Loss on extinguishment of debt (8)	2,926		2,806		
Other income (9)	842	13,372	6,404	5,919	2,746
Income (loss) before income tax expense (benefit)	(262,030)	(828,482)	215,759	306,354	290,026
Income tax expense (benefit)	(74,111)	(269,663)	71,459	107,250	101,003
Net income (loss)	$ (187,919)	$ (558,819)	$ 144,300	$ 199,104	$ 189,023
Earnings (loss) per common share (10)					
Basic	$ (2.51)	$ (7.36)	$ 1.89	$ 2.83	$ 2.91
Diluted	(2.51)	(7.36)	1.89	2.83	2.87
Dividends on common stock (11)	9,158	27,713	39,146	8,522	5,938
Cash dividends per common share (11)	0.12	0.36	0.51	0.12	0.09
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$ 156,266	$ 882,496	$ 688,597	$ 571,589	$ 444,043
Capital expenditures oil and natural gas properties	276,134	774,879	361,235	1,650,747	322,984

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	December 31, 2009	2008	2007	2006	2005
	(Dollars in thousands)				
Consolidated Balance Sheet Information:					
Cash and cash equivalents	$ 38,187	$ 357,552	$ 314,050	$ 39,235	$ 187,698
Total assets	1,326,833	2,056,186	2,812,204	2,609,685	1,064,520
Long-term debt	450,000	653,172	654,764	684,997	40,000
Shareholders equity	358,950	572,227	1,151,340	1,042,917	543,383

(1) In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico.

(2) In August 2006, we acquired working interests in approximately 100 oil and natural gas fields on 242 offshore blocks located in the Gulf of Mexico from Kerr-McGee Oil & Gas Corporation (Kerr-McGee) by merger.

(3) Included in lease operating expenses for the years ended December 31, 2009 and 2008 are hurricane remediation costs of $18.4 million and $17.7 million, respectively, related to Hurricanes Ike and Gustav that were either not yet approved by our insurance underwriters adjuster or were not covered by insurance. Included in lease operating expenses for the years ended December 31, 2007, 2006 and 2005 are $18.5 million, $0.5 million and $1.6 million, respectively, for hurricane remediation costs that were not covered by insurance.

(4) The carrying amount of our oil and natural gas properties has been written down by $218.9 million as of March 31, 2009 through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of lower natural gas prices at March 31, 2009, as compared to December 31, 2008. In December 2008, the carrying amount of our oil and natural gas properties was written down by $1.2 billion through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008. No such write-downs were required during the other years presented.

(5) In December 2004, our board of directors granted an employee bonus to all employees of record on December 31, 2004 (other than our Chief Executive Officer and our Secretary) in amounts equal to their 2004 salaries. The bonus was paid in two installments, on June 1, 2005 and January 3, 2006, to eligible individuals who were still in our employ on those dates. Approximately $2.6 million of expenses related to this bonus are included in general and administrative expenses (G&A) for 2005.

(6) G&A related to our long-term incentive compensation plans were $6.5 million, $11.6 million, $7.8 million, $8.4 million and $2.3 million in 2009, 2008, 2007, 2006 and 2005, respectively.

(7) In 2009, our derivative loss of $7.4 million included the recognition of realized and unrealized losses of $0.2 million and $5.4 million, respectively, related to our commodity derivative contracts. Also included in 2009 is an unrealized loss of $1.8 million related to our interest rate swap. In 2008, our derivative loss of $16.5 million consisted of a realized loss of $27.4 million related to commodity derivatives offset by a gain of $17.4 million related to a change in the fair value of such derivatives. Also included in 2008 are realized and unrealized losses of $2.6 million and $3.9 million, respectively, related to our interest rate swap that was de-designated as a cash flow hedge during 2007. In 2007, our derivative loss of $36.5 million consisted of an unrealized loss of $34.3 million related to commodity derivatives offset by a realized gain of $1.3 million related such derivatives. Also included in 2007 is an unrealized loss of $3.5 million related to our interest rate swap. In 2006, our derivative gain of $24.2 million consisted of realized and unrealized gains of $10.7 million and $13.5 million, respectively, related to commodity derivative contracts.

(8) In May 2009, we repaid the Tranche B term loan facility in full with borrowings under our revolving loan facility. We incurred a loss of $2.9 million related to the write-off of all the deferred financing costs related to the Tranche B term loan facility and the write-off of a portion of the deferred financing costs related to the revolving loan facility, as well as the incurrence of other incidental costs in connection with the payoff of the Tranche B term loan facility. In June 2007, we used a portion of the proceeds from our private offering of the Notes to prepay the balance outstanding on our Tranche A term loan facility and make a $90.0 million principal payment on our Tranche B term loan facility. We incurred a loss of $2.8 million

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related to the write-off of all the deferred financing costs related to the Tranche A term loan facility and a pro-rata portion of the deferred financing costs related to the Tranche B term loan facility.

(9) Consists of interest income.

(10) Earnings (loss) per share data for 2008, 2007, 2006 and 2005 has been calculated and restated retrospectively for comparability to the 2009 presentation. Refer to Note 16 to our consolidated financial statements.

(11) The amount for 2008 includes a special cash dividend of $20.84 million, or approximately $0.2729 per share, that was paid in December 2008. The amount for 2007 includes a special cash dividend of $30.0 million, or approximately $0.39 per share, that was declared in December 2007 and paid in January 2008.

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HISTORICAL RESERVE AND OPERATING INFORMATION

The following presents summary information regarding our estimated net proved oil and natural gas reserves and our historical operating data for the years shown below. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the SEC and give no effect to federal or state income taxes. For additional information regarding our reserves, please read Item 1 *Business* and Item 2 *Properties.* The selected historical operating data set forth below should be read in conjunction with Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations* and with our consolidated financial statements and the notes to those consolidated financial statements included elsewhere in this report.

	December 31, 2009	2008	2007	2006	2005
Reserve Data:					
Estimated net proved reserves (1)(2):					
Natural gas (Bcf)	165.8	227.9	332.8	401.2	215.9
Oil (MMBbls)	34.2	43.9	51.0	55.7	45.9
Total natural gas and oil (Bcfe)	371.0	491.1	638.8	735.2	491.5
Proved developed producing (Bcfe)	162.5	148.6	224.1	225.3	120.1
Proved developed non-producing (Bcfe) (3)	121.0	185.5	171.2	253.6	198.5
Total proved developed (Bcfe)	283.5	334.1	395.3	478.9	318.6
Proved undeveloped (Bcfe)	87.5	157.0	243.5	256.3	172.9
Proved developed reserves as a percentage of proved reserves	76.4%	68.0%	61.9%	65.1%	64.8%
Reserve additions (reductions) (Bcfe):					
Revisions (4)	(25.5)	(157.5)	(18.7)	(13.1)	20.3
Extensions and discoveries	23.4	47.2	48.4	109.3	60.6
Purchases of minerals in place	0.7	60.5	1.4	246.7	14.2
Sales of minerals in place	(23.9)		(1.0)		
Production	(94.8)	(97.9)	(126.5)	(99.2)	(71.1)
Net reserve additions (reductions)	(120.1)	(147.7)	(96.4)	243.7	24.0

	Year Ended December 31, 2009	2008	2007	2006	2005
Operating Data:					
Net sales:					
Natural gas (Bcf)	51.6	56.1	76.7	60.4	46.5
Oil (MMBbls)	7.2	7.0	8.3	6.5	4.1
Total natural gas and oil (Bcfe) (1)	94.8	97.9	126.5	99.2	71.1
Average daily equivalent sales (MMcfe/d)	259.7	267.5	346.7	271.7	194.7
Average realized sales prices (Unhedged):					
Natural gas ($/Mcf)	$ 3.97	$ 9.40	$ 7.20	$ 7.08	$ 8.27
Oil ($/Bbl)	55.67	98.72	67.58	57.70	48.85
Natural gas equivalent ($/Mcfe)	6.39	12.42	8.80	8.07	8.23
Average realized sales prices (Hedged) (5):					
Natural gas ($/Mcf)	$ 3.96	$ 9.42	$ 7.28	$ 7.23	$ 8.27
Oil ($/Bbl)	55.67	94.67	67.01	57.97	48.85
Natural gas equivalent ($/Mcfe)	6.38	12.14	8.81	8.18	8.23
Average per Mcfe ($/Mcfe):					
Lease operating expenses	$ 2.15	$ 2.35	$ 1.86	$ 1.15	$ 1.07

Gathering and transportation costs	0.14	0.16	0.12	0.16	0.17
Production costs	2.29	2.51	1.98	1.31	1.24
Production taxes	0.02	0.09	0.05	0.02	0.01
Depreciation, depletion, amortization and accretion	3.61	5.33	4.21	3.40	2.59
General and administrative expenses	0.45	0.48	0.31	0.38	0.34
	$ 6.37	$ 8.41	$ 6.55	$ 5.11	$ 4.18
Total number of wells drilled (gross)	13	26	9	34	29
Total number of productive wells drilled (gross)	10	20	8	27	23

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(1) Estimated reserves as of December 31, 2009 are based on the unweighted average of first-day-of-the-month commodity prices over the period January 2009 through December 2009 in accordance with current definitions and guidelines set forth by the SEC. Estimated reserves as of December 31, 2008, 2007, 2006 and 2005 are based on end-of-period commodity prices in accordance with the previous definitions and guidelines of the SEC in effect on those respective dates.
(2) One billion cubic feet equivalent (Bcfe), one million cubic feet equivalent (MMcfe) and one thousand cubic feet equivalent (Mcfe) are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding).
(3) Approximately 1.7 Bcfe and 53.9 Bcfe of reserves were shut-in at December 31, 2009 and 2008, respectively, because of damage caused by Hurricane Ike in September 2008. Approximately 20.2 Bcfe and 23.5 Bcfe of reserves were shut-in at December 31, 2006 and 2005, respectively, because of Hurricanes Katrina and Rita in 2005. Also, approximately 5.7 Bcfe of reserves were shut-in at December 31, 2006 because of damage to the High Island Pipeline System which occurred in December 2006.
(4) Revisions for 2009 included decreases attributable to the new reserve reporting requirements for oil and natural gas companies enacted by the SEC, which became effective for annual reporting periods ending on or after December 31, 2009. The initial application of these rules resulted in the removal of 23.2 Bcfe of proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded, as required. In addition, positive revisions of 27.5 Bcfe that would have resulted from using end-of-period commodity prices as of December 31, 2009 ($76.00 per barrel for oil and natural gas liquids and $5.79 per MMBtu for natural gas) were offset by 25.1 Bcfe, the impact of which is attributable to the new requirement that oil and natural gas reserves are to be measured using the 12-month average commodity price for each product ($57.65 per barrel for oil and natural gas liquids and $3.87 per MMBtu for natural gas). Also included in the revisions of previous estimates for 2009 are negative revisions of 4.7 Bcfe due to performance. For 2008, negative revisions due to pricing, performance and hurricane damage were 105.0 Bcfe, 42.4 Bcfe and 10.1 Bcfe, respectively.
(5) Data for 2009, 2008, 2007 and 2006 includes the effects of commodity derivative contracts that did not qualify for hedge accounting. We did not have any commodity derivative contracts in place during 2005.

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

The following discussion and analysis should be read in conjunction with our accompanying consolidated financial statements and the notes to those financial statements included elsewhere in this annual report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this annual report.

Overview

We are an independent oil and natural gas producer focused in the Gulf of Mexico. We have grown through acquisitions, exploitation and exploration and currently hold working interests in approximately 77 producing fields in federal and state waters. We operate wells accounting for approximately 76% of our average daily production. In recent years, we have acquired interests in acreage and wells in the deepwater (more than 500 feet of water) on the outer continental shelf. We have interests in leases covering approximately 0.9 million gross acres (0.6 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. We own interests in approximately 288 structures, 163 of which are located in fields that we operate.

In managing our business, we are concerned primarily with maximizing return on shareholders equity. To accomplish this primary goal, we focus on profitably increasing production and reserves. We strive to grow our reserves through acquisitions and our drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to continue to add reserves post-acquisition. For example, in January 2008, we closed on the acquisition of an additional interest in Ship Shoal 349 field for $116.6 million in cash. The acquisition increased our working interest in this field to 100% from approximately 59%, and the estimated proved oil and natural gas reserves acquired were 60.5 Bcfe. This acquisition was funded with cash on hand.

Our exploration efforts are balanced between discovering reserves associated with acquisitions and reserves associated with acreage already under lease. Historically, we have financed our exploratory drilling with net cash

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provided by operating activities. The investment associated with drilling a well and future development of a project principally depends upon the water depth of the well or project, 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. Certain risks are inherent in the oil and natural gas industry and our business, any one of which, if it occurs, can negatively impact our rate of return on shareholders equity. When projects are extremely capital intensive and involve substantial risk, we generally seek participants to share the risk.

We generally sell our oil and natural gas at the wellhead at current market prices or we 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. We market our products 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 financial condition, cash flow and results of operations are significantly affected by the volume of our oil and natural gas production and the price that we receive for such production. In 2009, our production volume was comprised of approximately 46% oil and 54% natural gas, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. During 2009, we sold an average of approximately 141 MMcf of natural gas per day and approximately 20,000 Bbls of oil per day, or a combined rate of 260 MMcfe per day. Primarily as a result of Hurricane Ike in early September 2008, our production, particularly during the second half of 2008 and the first half of 2009, was negatively affected by downtime experienced by third-party pipelines and processing facilities, and to a lesser extent, by damage to our facilities.

Oil and natural gas prices have been and are expected to remain volatile. During the second half of 2008, the prices of oil and natural gas decreased significantly in response to turmoil in the financial markets and a global economic recession. While oil prices have increased considerably since the end of 2008, natural gas prices remained weak during the majority of 2009, especially compared to our costs per Mcfe, in the wake of decreased demand related to economic conditions, increased supply and increased levels of natural gas in storage. The West Texas Intermediate posted price for oil was $76.00 per barrel at the end of 2009, representing an increase of 85.4% from $41.00 per barrel at the end of 2008. The Henry Hub spot price for natural gas was $5.79 per MMBtu at the end of 2009, representing an increase of 1.4% from $5.71 per MMBtu at the end of 2008. During the year ended December 31, 2009, the average realized sales prices of our oil and natural gas were $55.67 per barrel and $3.97 per Mcf, respectively. Although our average realized sales prices for oil and natural gas were lower in 2009 compared to 2008, the costs of goods and services that we consume in our normal operations remained proportionately high in the first half of 2009 as a result of commitments in 2008, which dramatically reduced our cash flows. Continued lower prices will negatively impact our future oil and natural gas revenues, earnings and liquidity. Declines in oil and natural gas prices after December 31, 2009 could result in ceiling test impairments of the carrying value of our oil and natural gas properties, issues with financial ratio debt compliance, and a reduction of the borrowing base associated with our credit agreement. Such declines may limit the willingness of financial institutions and investors to provide borrowings or capital to us and others in the oil and natural gas industry.

In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. In connection with these transactions, we reduced our asset retirement obligations by approximately $128.5 million and we received proceeds of approximately $32.2 million.

During the third quarter of 2009, we entered into commodity option contracts and a commodity swap contract to manage our exposure to commodity price risk from sales of oil and natural gas during the fiscal year ended December 31, 2010. In 2009, we recorded realized and unrealized losses of $0.2 million and $5.4 million, respectively, in earnings related to our commodity derivative contracts. In 2008, we recorded a realized loss of $27.4 million related to commodity derivatives offset by a gain of $17.4 million related to a change in the fair value of such derivatives. In 2007, we recorded an unrealized loss of $34.3 million related to commodity derivatives offset by a realized gain of $1.3 million related to such derivatives.

Our operating costs include the expense of operating our wells, platforms and other infrastructure in the Gulf of Mexico and transporting our products to the point of sale. Our operating costs are generally comprised of several components, including direct operating costs, repairs and maintenance, gathering and transportation costs, production taxes, workover costs and ad valorem taxes. Our operating costs depend in part on the type of commodity produced, the level of workover activity and the geographical location of the properties.

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

Applicable environmental regulations require us to remove our platforms after production has ceased, to plug and abandon all wells and to remediate any environmental damage our operations may have caused. The costs associated with our asset retirement obligations generally increase as we drill wells in deeper parts of the continental shelf and in the deepwater. We generally do not pre-fund our asset retirement obligations. The liability related to our asset retirement obligations was $348.8 million at December 31, 2009. Inherent in the present value calculation of our liability are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and changes in the legal, regulatory, environmental and political environments.

Results of Operations

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenues. Revenues decreased $604.6 million, or 49.7%, to $611.0 million for the year ended December 31, 2009 compared to 2008. Oil revenues decreased $287.4 million, natural gas revenues decreased $322.6 million and other revenues increased $5.4 million compared to 2008. The oil revenue decrease was caused by a 43.6% decrease in the average realized oil price to $55.67 per barrel in 2009 from $98.72 per barrel in 2008, partially offset by a 2.9% increase in sales volumes. The natural gas revenue decrease resulted from a 57.8% decrease in the average realized natural gas price to $3.97 per Mcf in 2009 from $9.40 per Mcf in 2008 and an 8.0% decrease in sales volumes. The sales volume increase for oil is primarily attributable to the startup of production at our Green Canyon 646 field (Daniel Boone) in September 2009. However, sales volumes for oil and natural gas were negatively affected in 2009 by the continued deferral of production caused by downtime experienced by third party pipelines and processing facilities damaged by Hurricane Ike in 2008, the sale of one of our fields in Louisiana state waters in the second quarter of 2009, the sale of 36 non-core oil and natural gas fields in the fourth quarter of 2009 and natural reservoir declines. During 2009, production of approximately 24 MMcfe per day, on average, remained shut-in due to hurricane damage. Production of approximately 9 MMcfe per day is currently shut-in due to hurricane damage and we expect the majority of this production will be reestablished in the first half of 2010. The increase in other revenues primarily relates to allowable reductions of cash payments for royalties owed to the MMS for transportation of its royalty share of our deepwater production through our subsea pipeline systems.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance costs, workovers and maintenance on our facilities, decreased to $2.15 per Mcfe in 2009 from $2.35 per Mcfe in 2008. On a nominal basis, lease operating expenses decreased $25.8 million to $203.9 million in

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2009 compared to 2008. The decrease is attributable to decreases in base lease operating expenses and facility expenditures of $23.4 million and $10.4 million, respectively. Offsetting these decreases were increases in insurance costs and workovers of $4.0 million and $3.3 million, respectively. The decrease in base lease operating expenses primarily reflects lower overall service and supply costs and the sale of certain non-core properties as described above. The decrease in facility expenditures relates to several projects that were completed in 2008 that did not recur in 2009. Included in lease operating expenses for 2009 and 2008 are $18.4 million and $17.7 million, respectively, of hurricane remediation costs related to Hurricanes Ike and Gustav that were either not yet approved by our insurance underwriters adjuster or were not covered by insurance. Lease operating expenses will be offset in future periods to the extent that these costs are recovered under our insurance policies.

Production taxes. Production taxes decreased $7.3 million to $1.5 million in 2009 primarily due to the sale of one of our fields in Louisiana state waters in the second quarter of 2009, lower production from fields in state waters of Texas and Louisiana and lower realized prices on sales of our oil and natural gas in 2009. Most of our production is from federal waters, where there are no production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased $2.3 million to $13.6 million in 2009 primarily due to the sale of one of our fields in Louisiana state waters in the second quarter of 2009 and the sale of 36 non-core oil and natural gas fields in the fourth quarter of 2009.

Depreciation, depletion, amortization and accretion. DD&A decreased to $342.5 million in 2009 from $521.8 million in 2008. The decrease is primarily attributable to a lower depreciable base resulting from ceiling test impairments of $1.2 billion and $218.9 million (as adjusted for a revision that is described in Note 19 to our consolidated financial statements) recognized at the end of 2008 and the first quarter of 2009, respectively, and a net reduction of our asset retirement obligations of $134.5 million primarily from the sale of certain assets and revisions to our estimates, partially offset by lower oil and natural gas reserves, compared to 2008. Total proved reserves decreased 120.1 Bcfe to 371.0 Bcfe at December 31, 2009 from 491.1 Bcfe at December 31, 2008, for a net reduction of 24.5%. Approximately 48.3 Bcfe of the reduction in our total proved reserves in 2009 is attributable to the new reserve reporting requirements for oil and natural gas companies enacted by the SEC and the Financial Accounting Standards Board (FASB), which became effective for annual reporting periods ending on or after December 31, 2009. As discussed earlier, the reduction in our total proved reserves associated with the new reserve reporting requirements resulted from the use of 12-month average commodity prices instead of end-of-period commodity prices in estimating our quantities of proved oil and natural gas reserves, as well as the removal of certain proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded, as required. The impact on our DD&A for 2009 related to the adoption of the new reserve reporting requirements was an approximate $7.6 million increase in DD&A. On a per Mcfe basis, DD&A was $3.61 for the year ended December 31, 2009, compared to $5.33 for the same period in 2008.

Impairment of oil and natural gas properties. At March 31, 2009, we recorded a ceiling test impairment of our oil and natural gas properties of $218.9 million through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of a further decline in natural gas prices at March 31, 2009 as compared to December 31, 2008. In December 2008, the carrying amount of our oil and natural gas properties was written down by $1.2 billion through application of the full cost ceiling limitation, primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008. For a more detailed discussion of the ceiling test, refer to *Critical Accounting Policies Impairment of oil and natural gas properties* below.

General and administrative expenses. G&A decreased to $43.0 million for the year ended December 31, 2009 from $47.2 million in the same period of 2008 primarily due to lower incentive compensation and travel expenses, partially offset by reduced overhead charges billed to joint operators. G&A expenses related to our long-term incentive compensation plans were $6.5 million and $11.6 million in the years ended December 31, 2009 and 2008, respectively (see Note 13 to our consolidated financial statements). On a per Mcfe basis, G&A

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was $0.45 per Mcfe for the year ended December 31, 2009, compared to $0.48 per Mcfe for the year ended December 31, 2008.

Derivative loss. For the year ended December 31, 2009, our derivative loss of $7.4 million included the recognition of realized and unrealized losses of $0.2 million and $5.4 million, respectively, related to our commodity derivative contracts. Also included in 2009 is an unrealized loss of $1.8 million related to our interest rate swap. For the year ended December 31, 2008, our derivative loss of $16.5 million consisted of a realized loss of $27.4 million related to commodity derivatives offset by a gain of $17.4 million related to a change in the fair value of such derivatives. Also included in 2008 are realized and unrealized losses of $2.6 million and $3.9 million, respectively, related to our interest rate swap that was de-designated as a cash flow hedge during 2007. For additional details about our derivatives, refer to Note 8 to our consolidated financial statements.

Interest expense. Interest expense incurred decreased to $46.7 million for the year ended December 31, 2009 from $54.0 million in the same period of 2008 primarily due to lower interest rates and lower debt outstanding during 2009. During 2009 and 2008, $6.7 million and $19.3 million, respectively, of interest was capitalized to unevaluated oil and gas properties.

Loss on extinguishment of debt. In May 2009, we repaid the Tranche B term loan facility in full with borrowings under our revolving loan facility. During the year ended December 31, 2009, we recorded a loss of $2.9 million related to the write-off of all the deferred financing costs related to the Tranche B term loan facility and the write-off of a portion of the deferred financing costs related to the revolving loan facility, as well as the incurrence of other incidental costs in connection with the payoff of the Tranche B term loan facility.

Other income. Other income, consisting of interest income, decreased to $0.8 million for the year ended December 31, 2009 from $13.4 million in the same period of 2008 mainly due to lower average daily cash balances and a reduction in market interest rates received on invested cash in 2009.

Income tax expense/benefit. An income tax benefit of $74.1 million and $269.7 million was recorded in 2009 and 2008, respectively, primarily as a result of a net operating loss for tax purposes in each of those years. As described above, in 2009 and 2008 we recorded an impairment of our oil and natural gas properties of $218.9 million and $1.2 billion, respectively. On November 6, 2009, the Worker, Homeownership and Business Assistance Act of 2009 was signed into law. A provision of this act provides an election to increase the carryback period for applicable net operating losses up to five years from two years. A tax benefit of $38.4 million was recorded during the fourth quarter of 2009 as a result of this legislation. The effective tax rate of 28.3% for 2009 includes the federal statutory rate of 35.0%, reduced primarily by the effect of a recapture of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code related to net operating loss carrybacks, as well as the incremental current period effect of a change in our valuation allowance for our deferred tax assets. The effective rate of 32.5% for 2008 includes the federal statutory rate of 35.0%, reduced primarily by the effect of a valuation allowance for our deferred tax assets.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues. Revenues increased $101.9 million, or 9.1%, to $1.2 billion for the year ended December 31, 2008. Oil revenues increased $127.2 million and natural gas revenues decreased $25.3 million. The oil revenue increase was caused by a 46.1% increase in the average realized price to $98.72 per barrel in 2008 from $67.58 per barrel in 2007, partially offset by a 15.7% decrease in sales volumes. The natural gas revenue decrease resulted from a 26.9% decrease in sales volumes, partially offset by a 30.6% increase in the average realized natural gas price to $9.40 per Mcf in 2008 from $7.20 per Mcf in 2007. Sales volumes for oil and natural gas declined in 2008 primarily due to the deferral of production caused by Hurricane Gustav in late August 2008 and Hurricane Ike in early September 2008, partially offset by increases resulting from our successful exploration and development efforts, the acquisition of Apache s interest in Ship Shoal 349 field and several recompletions. Prior to Hurricane Gustav our production was averaging approximately 324 MMcfe per day. After the hurricanes we were almost totally shut-in for about a month, and when production resumed we were producing about 72

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MMcfe per day. Following a slow ramp up, our exit rate at the end of 2008 was 221 MMcfe per day. We believe that approximately 21.7 Bcfe of net production was deferred during 2008 as a result of damage caused by Hurricane Ike and, to a lesser extent, by Hurricane Gustav.

Lease operating expenses. Lease operating expenses increased to $2.35 per Mcfe in 2008 from $1.86 per Mcfe in 2007. Lower production volumes during 2008 resulted in an increase in lease operating expenses per Mcfe of $0.54, which was partially offset by a decrease of $0.05 per Mcfe caused by lower lease operating expenses. On a nominal basis, lease operating expenses decreased $5.0 million to $229.8 million in 2008, compared to 2007. The decrease of $5.0 million is attributable to decreases in insurance costs, facility expenditures and hurricane repair costs of $4.2 million, $1.4 million and $0.8 million, respectively, and lower workover expenditures of $6.8 million primarily associated with various non-operated properties. Offsetting these decreases was an increase in base lease operating expenses of $8.2 million. The increase in base lease operating expenses is primarily related to the acquisition of an additional interest in Ship Shoal 349 from Apache, increases in field salaries and incentive compensation and higher fuel costs. Included in lease operating expenses for 2008 are $17.7 million of hurricane remediation costs related to Hurricanes Ike and Gustav that were either not yet approved by our underwriters adjuster or were not covered by insurance. Lease operating expenses will be offset in future periods to the extent that these costs are recovered under our insurance policies. The 2007 period included $18.5 million of hurricane remediation costs related to Hurricanes Katrina and Rita that were not covered by insurance.

Production taxes. Production taxes increased $2.9 million to $8.8 million in 2008 primarily due to new production from fields in state waters of Texas and Louisiana and higher realized prices on sales of our oil and natural gas. Most of our production is from federal waters, where there are no production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $0.4 million to $16.0 million in 2008 primarily due to an increase in third-party processing fees for the production of natural gas liquids, partially offset by the deferral of production caused by Hurricanes Ike and Gustav.

Depreciation, depletion, amortization and accretion. DD&A decreased to $521.8 million in 2008 from $532.9 million in 2007. The decrease is primarily attributable to lower volumes of oil and natural gas produced in 2008, partially offset by capital expenditures, an increase in our estimated asset retirement obligations of $111.1 million (see Note 2 to our consolidated financial statements) and lower total proved reserves in 2008. Total proved reserves decreased 147.7 Bcfe to 491.1 Bcfe at December 31, 2008 from 638.8 Bcfe at December 31, 2007, a net reduction of 23.1%. This decrease in reserves is largely due to the significant decline in both oil and natural gas prices as of December 31, 2008. On a per Mcfe basis, DD&A was $5.33 for the year ended December 31, 2008, compared to $4.21 for the same period in 2007.

Impairment of oil and natural gas properties. In December 2008, the carrying amount of our oil and natural gas properties was written down by $1.2 billion through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008. For a more detailed discussion of the ceiling test, refer to *Critical Accounting Policies Impairment of oil and natural gas properties* below.

General and administrative expenses. G&A increased to $47.2 million for the year ended December 31, 2008 from $38.9 million in the same period of 2007 primarily due to an increase in the number of employees and higher salaries and other employee benefits. G&A expenses related to our long-term incentive compensation plans were $11.6 million and $7.8 million in the years ended December 31, 2008 and 2007, respectively (see Note 13 to our consolidated financial statements). On a per Mcfe basis, G&A was $0.48 per Mcfe for the year ended December 31, 2008, compared to $0.31 per Mcfe for the year ended December 31, 2007.

Derivative loss. For the year ended December 31, 2008, our derivative loss of $16.5 million consisted of a realized loss of $27.4 million related to commodity derivatives offset by a gain of $17.4 million related to a change in the fair value of such derivatives. Also included in 2008 are realized and unrealized losses of $2.6

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million and $3.9 million, respectively, related to our interest rate swap that was de-designated as a cash flow hedge during 2007. For the year ended December 31, 2007, our derivative loss of $36.5 million consisted of an unrealized loss of $34.3 million related to commodity derivatives offset by a realized gain of $1.3 million related to such derivatives. Also included in 2007 is an unrealized loss of $3.5 million related to our interest rate swap. For additional details about our derivatives, refer to Note 8 to our consolidated financial statements.

Interest expense. Interest expense incurred decreased to $54.0 million for the year ended December 31, 2008 from $62.2 million in the same period of 2007 primarily due to a lower average interest rate and lower debt outstanding during 2008. During 2008 and 2007, $19.3 million and $25.1 million, respectively, of interest was capitalized to unevaluated oil and gas properties.

Other income. Other income, consisting of interest income, increased to $13.4 million for the year ended December 31, 2008 from $6.4 million in the same period of 2007 mainly due to higher average daily cash balances in 2008.

Income tax expense/benefit. An income tax benefit of $269.7 million was recorded in 2008, compared to income tax expense of $71.5 million in 2007. The income tax benefit in 2008 is primarily the result of an impairment of our oil and natural gas properties of $1.2 billion as described above. The effective tax rate of 32.5% for 2008 includes the federal statutory rate of 35.0%, reduced primarily by the effect of a valuation allowance for our deferred tax assets. Our effective tax rate for the year ended December 31, 2007 was 33.1% and is below the statutory rate of 35.0% primarily because of the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code.

Liquidity and Capital Resources

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

Cash flow and working capital. Net cash provided by operating activities for the year ended December 31, 2009 was $156.3 million, compared to $882.5 million for 2008. Net cash used in investing activities totaled $237.7 million and $773.9 million during 2009 and 2008, respectively, which primarily represents our investment in oil and natural gas properties. At December 31, 2009, we had a cash balance of $38.2 million and we had $404.8 million of undrawn capacity available under the revolving portion of the Credit Agreement. Under the terms of the Credit Agreement, we are subject to various financial covenants calculated as of the last day of each fiscal quarter. As of December 31, 2009, we were in compliance with such financial covenants. See *Long-term debt* and Note 6 to our consolidated financial statements for more information regarding our Credit Agreement. We believe that cash provided by operations, borrowings available under our revolving loan facility and other external sources of liquidity should be sufficient to fund our ongoing cash requirements.

Net cash provided by operating activities decreased in 2009 compared to 2008 due to several factors. In 2009, net cash provided by operating activities was unfavorably impacted by a $5.76 per Mcfe, or 47%, decrease in our average realized sales price for our oil and natural gas production, lower sales volumes of natural gas, lower interest income and decreases in working capital, compared to 2008. Offsetting these unfavorable factors were decreases in lease operating expenses, production taxes, gathering and transportation costs, general and administrative expenses, interest expense incurred and realized losses on settlements of our derivative contracts. Net cash provided by operating activities increased in 2008 compared to 2007 due to increases in the average prices we realized on sales of our oil and natural gas, lower interest expense incurred and higher interest income. Offsetting these favorable factors were lower volumes of oil and natural gas sold, higher realized losses on settlements of our derivative contracts and higher general and administrative expenses in 2008 as compared to 2007.

While oil prices have increased considerably since the end of 2008, natural gas prices remained weak during the majority of 2009, especially compared to our costs per Mcfe, in the wake of decreased demand related to

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economic conditions, increased supply and increased levels of natural gas in storage. The West Texas Intermediate posted price for oil was $76.00 per barrel at the end of 2009, representing an increase of 85.4% from $41.00 per barrel at the end of 2008. The Henry Hub spot price for natural gas was $5.79 per MMBtu at the end of 2009, representing an increase of 1.4% from $5.71 per MMBtu at the end of 2008. During the year ended December 31, 2009, the average realized sales prices of our oil and natural gas were $55.67 per barrel and $3.97 per Mcf, respectively. Although our average realized sales prices for oil and natural gas were lower in 2009 compared to 2008, the costs of goods and services that we consume in our normal operations remained proportionately high in the first half of 2009 as a result of commitments in 2008, which dramatically reduced our cash flows.

As a result of Hurricanes Ike and Gustav, our production was negatively affected in the fourth quarter of 2008 and the first half of 2009 by the downtime experienced by third-party pipelines and processing facilities and, to a lesser extent, by damage to our facilities. Prior to Hurricane Gustav in late August 2008, our production was averaging approximately 324 MMcfe per day. During the fourth quarter of 2008, our production averaged approximately 176 MMcfe per day, and during the first half of 2009 our production averaged approximately 255 MMcfe per day. For the year ended December 31, 2009, our production averaged approximately 260 MMcfe per day. In 2009, our oil sales volumes increased from 2008 levels primarily due to the startup of production at our Green Canyon 646 field (Daniel Boone) in September 2009. However, sales volumes for oil and natural gas were negatively affected in 2009 by the continued deferral of production caused by downtime experienced by third party pipelines and processing facilities damaged by Hurricane Ike in 2008, the sale of one of our fields in Louisiana state waters in the second quarter of 2009, the sale of 36 non-core oil and natural gas fields in the fourth quarter of 2009 and natural reservoir declines. During 2009, production of approximately 24 MMcfe per day, on average, remained shut-in due to hurricane damage. Production of approximately 9 MMcfe per day is currently shut-in due to hurricane damage and we expect the majority of this production will be reestablished in the first half of 2010.

From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our credit facility. In the third quarter of 2009, we entered into commodity swap and option contracts relating to approximately 20 Bcfe of our anticipated production in 2010. For additional details about our derivatives, refer to Item 7A *Quantitative and Qualitative Disclosures About Market Risk* and Note 8 to our consolidated financial statements.

Disruptions in the Capital Markets and Impact on Liquidity. Although there have been significant disruptions in the U.S. and global capital markets, we have not experienced any disruptions to our liquidity. During the first quarter of 2009, we made a principal payment of $0.8 million on our Tranche B term loan facility. In May 2009, the Company paid in full the Tranche B term loan facility outstanding balance of $204.75 million, plus accrued and unpaid interest of $0.7 million, with borrowings under the revolving loan facility. In June 2009, we repaid $62.9 million of borrowings under the revolving loan facility, and in December 2009, we repaid the remaining amount outstanding under the revolving loan facility of $142.5 million. Both of these debt repayments were funded with cash on hand. At December 31, 2009, our cash on hand was $38.2 million and we had $404.8 million of undrawn capacity under our revolving loan facility, which matures in 2012.

Availability under the Credit Agreement is subject to a semi-annual borrowing base redetermination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their valuation of our proved reserves and their own internal criteria. In April 2009, our lenders reduced the borrowing base from $710 million to $405.5 million. In November 2009, our borrowing base of $405.5 million was reaffirmed by our lenders. Sixteen lenders participate in our revolving loan facility and we do not anticipate any of them being unable to satisfy their obligations under the Credit Agreement. We do not anticipate any immediate need for access to the capital markets. However, because of various factors, including our credit rating and our reserve and production profile, it could be difficult and/or expensive to obtain debt or equity capital funding at sufficient levels in the future. We expect the next borrowing base redetermination to be finalized in April 2010.

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Hurricane Remediation and Insurance Claims. During the third quarter of 2008, Hurricane Ike, and to a much lesser extent Hurricane Gustav, caused property damage and disruptions to our exploration and production activities. We currently have insurance coverage for named windstorms but we do not carry business interruption insurance. Our insurance policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention of $10 million per occurrence that must be satisfied by us before we are indemnified for losses. In the fourth quarter of 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. Our insurance coverage policy limits at the time of Hurricane Ike were $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The damage we incurred as a result of Hurricane Gustav was well below our retention amount.

For a summary of remediation costs related to Hurricanes Ike and Gustav that were included in lease operating expenses during the years ended December 31, 2009 and 2008, refer to Note 12 to our consolidated financial statements. Lease operating expenses will be offset in future periods to the extent that such costs are recovered under our insurance policies. As discussed in further detail below, included in lease operating expenses for the year ended December 31, 2007 is $18.5 million for remediation costs related to Hurricanes Katrina and Rita that were not covered by insurance.

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection. Our assessment of probability considers the review and approval of such costs by our insurance underwriters adjuster. Claims that have been processed in this manner have been paid on a timely basis.

To the extent our insurance underwriters adjuster has reviewed work plans and other information provided by us in connection with our plugging and abandonment activities scheduled to be completed and that were accelerated by Hurricane Ike, and has indicated that our insurance policies provide coverage for such costs and they are within policy limits, we have recognized an insurance receivable. See Note 2 to our consolidated financial statements for additional information about the impact of Hurricane Ike on our asset retirement obligations.

At December 31, 2009, $1.3 million of remediation costs and $29.2 million related to the plugging and abandonment of wells and dismantlement of facilities damaged by Hurricane Ike are included in insurance receivables. Refer to Note 12 to our consolidated financial statements for a reconciliation of our insurance receivables from December 31, 2008 to December 31, 2009. We expect that our available cash and cash equivalents, cash flow from operations and the availability under our credit facility will be sufficient to meet any necessary expenditures that may exceed our insurance coverage for damages incurred as a result of Hurricanes Ike and Gustav.

Due to increased insurance claims in recent years associated with hurricanes in the Gulf of Mexico and continuing restrictions in the capital markets, property damage and well control insurance coverage has become more limited and the cost of such coverage has increased. In June 2009, we renewed our insurance policies covering well control and hurricane damage at a cost of approximately $35 million. The current policy limits for well control and hurricane damage are $100 million and $85 million, respectively, with an additional $100 million for well control and hurricane damage on our Ship Shoal 349 field. A retention of $35 million per occurrence must be satisfied by us before we are indemnified for losses, and certain properties we have deemed as non-core are not covered for hurricane damage. However, properties representing approximately 89.3% of our PV-10 value at December 31, 2009 (before estimated asset retirement obligations) are covered under our new insurance policies for hurricane damage. Our insurers may not continue to offer this type and level of coverage to us, or our costs may increase substantially as a result of increased premiums and the increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have a claim, the insurance companies will not pay our claim.

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However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. On May 1, 2009, we renewed our general and excess liability insurance policies.

In March 2007, we entered into agreements with our insurance underwriters to settle all claims related to Hurricanes Katrina and Rita, as well as a claim to recover drilling costs on a well at Green Canyon 82 that experienced uncontrollable water flow in the second quarter of 2006. After adjustments for applicable deductibles and reimbursements of $21.9 million received in 2006 and $4.8 million received in February 2007, the Company received proceeds of $73.3 million in March 2007. Total reimbursements of $78.1 million received in the first quarter of 2007 exceeded our insurance receivables at December 31, 2006 by $2.9 million. Such amount was used to offset a portion of our hurricane remediation costs incurred in 2007, which totaled $25.2 million. In the third quarter of 2007, we recovered $3.8 million under the insurance policy of one of our partners, which also offset a portion of our hurricane remediation costs incurred in 2007. Included in lease operating expenses for the year ended December 31, 2007 is $18.5 million for hurricane remediation expenses that were not covered by insurance.

Capital expenditures. The level of our investment in oil and natural gas properties changes from time to time depending on numerous factors, including the prices of oil and natural gas, acquisition opportunities and the results of our exploration and development activities. For the year ended December 31, 2009, our capital expenditures for oil and natural gas properties and equipment of $276.1 million included $90.6 million for exploration activities, $162.1 million for development activities and $23.4 million for seismic, capitalized interest and other leasehold costs. Our development and exploration capital expenditures consisted of $202.2 million on the conventional shelf and other projects, $45.9 million in the deepwater and $4.6 million on the deep shelf. Our capital expenditures for the year ended December 31, 2009 were financed by net cash from operating activities and cash on hand.

During 2009, we participated in the drilling of 10 gross exploratory wells and three gross development wells, of which 12 were on the conventional shelf and one was on the deep shelf. Two of the development wells were successful and eight of the exploratory wells were successful. We operate five of the eight successful exploratory wells.

During 2008, our oil and natural gas investments totaled $774.9 million, including drilling 24 gross exploratory wells and two gross development wells. During 2007, we invested $361.2 million in oil and natural gas properties, including the drilling of seven gross exploratory wells and two gross development wells. The wells we drilled over the past three years have tended to be deeper or were more technologically challenging than our past drilling projects and, consequently, have been more expensive to drill.

Our total capital expenditure budget for 2010 is $450 million. We anticipate fully funding our 2010 capital budget with internally generated cash flow and cash on hand. The budget includes seven conventional shelf exploration wells and other capital items such as well recompletions, facilities capital, seismic and leasehold items. At this time, we anticipate these capital expenditures will cost approximately $150 million. The balance of the $450 million budget will be allocated to acquisitions, additional drilling opportunities from the company s prospect inventory and/or new joint ventures offshore (on the shelf and in the deepwater) and onshore. Our 2010 capital budget is subject to change as conditions warrant. We are determined to remain as flexible as possible and believe this strategy holds the best promise for value creation and growth.

Periodically, we sell oil and gas properties that we identify as non-core, which we define as either having limited exploration or exploitation potential or that are not expected to yield our desired return on equity when abandonment costs are considered. In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. In connection with these transactions, we reduced our asset retirement obligations by approximately $128.5 million and we received proceeds of approximately $32.2 million.

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Long-term debt. The Credit Agreement is a secured facility that is collateralized by our oil and natural gas properties. Availability under the Credit Agreement is subject to a semi-annual borrowing base redetermination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their valuation of our proved reserves and their own internal criteria. In April 2009, our lenders reduced the borrowing base from $710.0 million to $405.5 million. In November 2009, our borrowing base of $405.5 million was reaffirmed by our lenders. Any determination by our lenders to reduce our borrowing base will cause a similar reduction in the availability under our revolving loan facility.

In June 2007, the Company used proceeds from the Notes to pay in full the Tranche A term loan facility outstanding balance of $50.0 million and to make a payment of $90.0 million on the Tranche B term loan facility balance outstanding. The Company also used proceeds from the Notes to pay the revolving loan facility balance then outstanding of $271.0 million. During the year ended December 31, 2007, we recorded a loss of $2.8 million related to the write-off of all the deferred financing costs related to the Tranche A term loan facility and a pro-rata portion of the deferred financing costs related to the Tranche B term loan facility.

On July 24, 2008, certain amendments were made to the Credit Agreement, including an amendment to extend the maturity of the revolving loan facility under the Credit Agreement to July 23, 2012 and increase the interest margin. Other amendments have subsequently been made to the Credit Agreement, including amendments related to share repurchases, dividends and interest margins.

During the first quarter of 2009, we made a principal payment of $0.8 million on our Tranche B term loan facility. In May 2009, the Company paid in full the Tranche B term loan facility outstanding balance of $204.75 million, plus accrued and unpaid interest of $0.7 million, with borrowings under the revolving loan facility. In June 2009, we repaid $62.9 million of borrowings under the revolving loan facility, and in December 2009, we repaid the remaining amount outstanding under the revolving loan facility of $142.5 million. Both of these debt repayments were funded with cash on hand. During the year ended December 31, 2009, we recorded a loss of $2.9 million related to the write-off of all the deferred financing costs related to the Tranche B term loan facility and the write-off of a portion of the deferred financing costs related to the revolving loan facility, as well as the incurrence of other incidental costs in connection with the payoff of the Tranche B term loan facility. The Credit Agreement provides for the availability of letters of credit for up to $90.0 million, provided however, that its usage is subject to availability under the revolving loan. At December 31, 2009, we had $0.7 million of letters of credit outstanding and our remaining availability under the revolving loan facility was $404.8 million. Borrowings outstanding under the Notes were $450.0 million at December 31, 2009, all of which are classified as long-term. We currently have no repayments of debt due until June 2014. In January 2010, we borrowed $142.5 million under our revolving loan facility. For additional details about our long-term debt, see Note 6 to our consolidated financial statements.

Effective May 4, 2009, borrowings under the revolving loan facility bear interest at either (1) the highest of the Prime Rate, the Federal Funds Rate plus 0.50%, or the one-month Eurodollar Rate plus 1.0%, plus a margin which varies from 0.75% to 1.75% depending on the level of total borrowings under the Credit Agreement, or (2) to the extent the loan outstanding is designated as a Eurodollar loan, at the London Interbank Offered Rate (LIBOR) plus a margin that varies from 2.0% to 3.0% depending on the level of total borrowings under the Credit Agreement. The Credit Agreement also bears an unused commitment fee of 0.50%. The estimated effective interest rate on the revolving loan facility, including unused commitment fees and amortization of deferred financing costs, was 4.8% during the year ended December 31, 2009.

The Credit Agreement contains covenants that restrict the payment of cash dividends and share repurchases (currently limited to $60.0 million per year), borrowings other than from the facilities, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. We are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio, as such ratios are defined in the Credit Agreement. In connection with the April 2009 borrowing base redetermination, we amended the maximum leverage ratio, which is the ratio of total debt to EBITDA (as those terms are defined in the Credit Agreement), to

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be 3.75 to 1 for the four quarters ended September 30, 2009, 3.50 to 1 for the four quarters ended December 31, 2009, 3.25 to 1 for the four quarters ended March 31, 2010 and 3.00 to 1 thereafter. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2009.

During the year ended December 31, 2008, we made principal payments of $3.0 million under our Credit Agreement. During the year ended December 31, 2007, we borrowed and repaid $458.0 million and $946.5 million, respectively, under our Credit Agreement and we issued $450.0 million of Notes.

Asset retirement obligations. Each year (or more often if conditions warrant) we review, and to the extent necessary, revise our asset retirement obligation estimates. During 2008 we revised our estimate of the cost to decommission our sub-sea wells and made other changes to the estimated timing and amounts of settlements. In addition, we increased our estimated liabilities for decommissioning platforms that were damaged by Hurricane Ike. In 2009, we reduced our asset retirement obligations by $99.1 million for work performed to settle our liabilities (including $51.9 million to plug and abandon wells and facilities damaged by Hurricane Ike) and by $128.5 million for asset dispositions. In addition, we decreased our estimates of future asset retirement obligations by $96.5 million, a portion of which relates to useful life extensions while the remainder primarily relates to recent cost reductions we experienced in the marketplace for decommissioning, site clearance and removal of certain of our operated structures and pipelines. Conversely, our estimated asset retirement obligations increased by $12.8 million related to additional interests we acquired in certain fields during the fourth quarter of 2009 and by $77.2 million, the majority of which relates to revised estimates for the dismantlement of two operated platforms that were toppled during Hurricane Ike and the plugging and abandonment of the associated wells. The remainder of the increase relates to revised estimates related to other wells and facilities damaged by such storm.

Contractual obligations. The following summarizes our significant contractual obligations by maturity as of December 31, 2009. At December 31, 2009, we had no capital leases or long-term contracts for drilling rigs or equipment.

		Payments Due by Period at December 31, 2009			
	Total	**Less Than One Year**	**One to Three Years**	**Three to Five Years**	**More Than Five Years**
			(Dollars in millions)		
Long-term debt principal	$ 450.0	$	$	$ 450.0	$
Long-term debt interest (1)	167.1	37.1	74.3	55.7	
Drilling rigs	20.4	20.4			
Operating leases	4.4	2.0	2.3	0.1	
Asset retirement obligations	348.8	117.4	28.1	56.5	146.8
Derivatives	9.9	9.9			
Other liabilities	2.4		2.4		
	$ 1,003.0	$ 186.8	$ 107.1	$ 562.3	$ 146.8

(1) Includes interest on our Notes, which bear interest at a fixed rate of 8.25%. Interest was calculated through the stated maturity date of the related debt.

Inflation and Seasonality

Inflation. While we benefited from a general increase in our realized sales prices for oil and natural gas for several years until July 2008, the cost of goods and services that we depend on to execute our drilling program and operate our properties also increased significantly. During the second half of 2008, the prices of oil and natural gas decreased significantly in response to turmoil in the financial markets and a global economic recession, without a corresponding decrease in our costs for goods and services. As a result, our operating margins and profitability decreased significantly in the second half of 2008. In the second half of 2009, oil prices increased considerably and we experienced reductions in our costs for goods and services, resulting in

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improvements to our operating margins and profitability. However, natural gas prices remained weak during the majority of 2009 and our operating margins and profitability have not recovered to their historical levels. Unless another economic collapse occurs, in 2010 we expect the costs for goods and services to continue to increase while the demand for oil and natural gas should remain at or above current levels.

Seasonality. Generally, the demand for and price of natural gas increases during the winter months and decreases during the summer months. However, these seasonal fluctuations are somewhat reduced because during the summer, pipeline companies, utilities, local distribution companies and industrial users purchase and place into storage facilities a portion of their anticipated winter requirements of natural gas. Crude oil is also impacted by generally higher prices during winter months. Seasonal weather changes affect our operations. Tropical storms and hurricanes occur in the Gulf of Mexico during the summer and fall, which require us to evacuate personnel and shut-in production until these storms subside. Also, periodic storms during the winter often impede our ability to safely load, unload and transport personnel and equipment, which delays the installation of production facilities, thereby delaying sales of our oil and natural gas.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates. Our significant accounting policies are detailed in Note 1 to our consolidated financial statements. We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue recognition. We recognize oil and natural gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collection is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties in which there is joint ownership. Under this method, we record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which the Company has taken less than its ownership share of production. At December 31, 2009 and 2008, $6.5 million and $7.0 million, respectively, was included in current liabilities related to natural gas imbalances.

Full-cost accounting. We account for our investments in oil and natural gas properties using the full-cost method of accounting. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and gas properties are capitalized. Capitalization of geological and geophysical costs, certain employee costs and G&A expenses related to these activities is permitted. We capitalize external geological and geophysical costs, which mainly consist of seismic costs. We expensed approximately $4.1 million, $4.7 million and $4.1 million in geological and geophysical administrative costs during 2009, 2008 and 2007, respectively.

We amortize our investment in oil and natural gas properties, capitalized asset retirement obligations and future development costs (including asset retirement obligations of wells to be drilled) through DD&A, using the units of production method. The cost of unproved properties related to significant acquisitions are excluded from the amortization base until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. The costs of drilling non-commercial exploratory wells are included in the amortization base immediately upon determination that such wells are

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non-commercial. Total unproved properties excluded from amortization at December 31, 2009 and 2008 were $77.3 million and $99.1 million, respectively.

We capitalize interest on expenditures made in connection with the exploration and development of unproved properties that are excluded from the amortization base. Interest is capitalized only for the period that exploration and development activities are in progress. We capitalized $6.7 million, $19.3 million and $25.1 million of interest expense during the years ended December 31, 2009, 2008 and 2007, respectively.

Under the full-cost method, sales of oil and natural gas properties are accounted for as adjustments to capitalized costs with no gain or loss recognized unless an adjustment would significantly alter the relationship between capitalized costs and the value of proved reserves.

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

Impairment of oil and natural gas properties. Under the full cost method of accounting, we are required to periodically perform a ceiling test, which determines a limit on the book value of our oil and natural gas properties. If the net capitalized cost of oil and natural gas properties (including capitalized asset retirement obligations), net of related deferred income taxes, exceeds the present value of estimated future net revenues from proved reserves discounted at 10%, plus the cost of unproved oil and natural gas properties not being amortized, plus the lower of cost or estimated fair value of unproved oil and natural gas properties included in the amortization base, net of related tax effects, the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization. Any such write downs are not recoverable or reversible in future periods. Estimated future net revenues used in the ceiling test as of December 31, 2009 are based on the unweighted average of first-day-of-the-month commodity prices over the period January 2009 through December 2009 and exclude future cash outflows related to capitalized asset retirement obligations and include future development costs and asset retirement obligations related to wells to be drilled. Primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008, we recorded a ceiling test impairment at December 31, 2008 of $1.2 billion. At March 31, 2009, we recorded an additional ceiling test impairment of $218.9 million primarily as a result of a further decline in natural gas prices at March 31, 2009 as compared to December 31, 2008. Declines in oil and natural gas prices after December 31, 2009 may require us to record additional ceiling test impairments in the future. We did not have a ceiling test impairment during the year ended December 31, 2007.

Oil and natural gas reserve quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. We make changes to depletion rates and impairment calculations in the same period that changes to our reserve estimates are made. Our proved reserve information as of December 31, 2009 included in this Annual Report on Form 10-K was estimated by our independent petroleum consultant, Netherland, Sewell & Associates, Inc., in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, severance taxes, development costs and workovers, all of which may vary considerably from actual results;

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- 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.

In December 2008, the SEC issued its final rule on the Modernization of Oil and Gas Reporting, which is effective for annual reporting periods ending on or after December 31, 2009. For additional information about our proved reserves and the impact of the new rules on our accounting and disclosure, refer to Item 2 *Properties* *Proved Reserves* and Notes 1 and 20 to our consolidated financial statements.

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

Inherent in the present value calculation of our liability are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of our existing abandonment liability, we will make corresponding adjustments to our oil and natural gas property balance. In addition, increases in the discounted abandonment liability resulting from the passage of time will be reflected as accretion expense in our consolidated statement of income.

Fair value measurements. Effective January 1, 2008, we adopted the provisions of the *Fair Value Measurements and Disclosures* Topic of the Codification on a prospective basis for all of our financial assets and liabilities that are required to be measured at fair value. In February 2008, the FASB granted a one-year deferral of the provisions of this Topic for certain non-financial assets and liabilities, and accordingly, asset retirement obligations incurred after December 31, 2008 are initially measured at fair value in accordance with the *Fair Value Measurements and Disclosures* Topic of the Codification. The adoption of the provisions of this Topic did not have a material impact on our financial statements.

We measure the fair value of our derivative financial instruments by applying the income approach, using inputs that are derived principally from observable market data. The estimated fair value of the Notes, as disclosed in the notes to our consolidated financial statements, is based on quoted prices.

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

We recognize uncertain tax positions in our financial statements when it is more likely than not that we will sustain the benefit taken or expected to be taken. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense.

Share-based compensation. In accordance with the *Compensation Stock Compensation* Topic of the Codification, we recognize compensation cost for share-based payments to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of the grant.

New Accounting Policies and Pronouncements

In January 2010, the FASB issued certain amendments to the *Extractive Activities Oil and Gas* Topic of the Codification that updated and aligned the FASB s reserve estimation and disclosure requirements for oil and natural gas companies with the reserve estimation and disclosure requirements that were adopted by the SEC in December 2008. Collectively, the new rules permit the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of *proved reserves* which was changed to indicate, among other things, that commencing with year-end 2009 entities must use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than end-of-period commodity prices, when estimating quantities of proved reserves. Similarly, the prices used to calculate the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future cash flows have been changed from end-of-period commodity prices to the 12-month average commodity prices used in calculating proved reserves. Beginning in the fourth quarter of 2009, the estimated future net revenues used to calculate the ceiling test are based on the 12-month average commodity price for each product. Also, because it is our policy to use end-of-period reserves in the determination of quarterly depletion, our DD&A expense for the fourth quarter of 2009 was calculated using proved reserves at December 31, 2009 that were determined in accordance with the new rules. Additionally, entities must separately disclose information about reserve quantities and certain financial statement amounts for geographic areas that represent 15 percent or more of proved reserves, and equity-method investees should be included in determining whether an entity has significant oil and gas producing activities. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, 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. These amendments to the Codification became effective for annual reporting periods ending on or after December 31, 2009. For additional information about our proved reserves and the impact of the new rules on our accounting and disclosure, refer to Item 2 *Properties Proved Reserves* and Notes 1 and 20 to our consolidated financial statements.

In April 2009, the FASB issued certain amendments to the *Financial Instruments* Topic of the Codification that require public companies to include disclosures about the fair value of their financial instruments in interim reporting periods, as well as the methods, significant assumptions and any changes in such methods and assumptions used to estimate the fair value of financial instruments. These amendments became effective for interim reporting periods ending after June 15, 2009. The adoption of these amendments to the Codification did not have a material impact on the Company s financial statements.

In accordance with the *Earnings Per Share* Topic of the Codification, effective January 1, 2009, the Company adopted certain amendments to the accounting principles relating to its calculation of earnings (loss) per share. The amendments provide that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in

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the computation of earnings per share under the two-class method. For additional information about the impact of the adoption of these amendments to the Codification on our financial statements, refer to Note 16 to our consolidated financial statements.

Effective January 1, 2009, the Company adopted certain amendments to the *Business Combinations* Topic of the Codification that require the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree to be measured at their respective fair values at the acquisition date. These amendments require the acquirer to record the fair value of contingent consideration (if any) at the acquisition date. Acquisition-related costs incurred prior to an acquisition are required to be expensed rather than included in the purchase-price determination. Also included in the amendments are guidance for recognizing and measuring the goodwill acquired in a business combination and guidance for determining what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of a business combination. These amendments apply prospectively to business combinations for which the acquisition date is on or after January 1, 2009. We expect these amendments will have an impact on our consolidated financial statements, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of acquisitions, if any, that we may consummate in the future.

Effective January 1, 2009, the Company adopted certain amendments to the *Consolidation* Topic of the Codification that establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. The adoption of these amendments to the Codification did not have a material impact on the Company s financial statements.

Effective January 1, 2009, the Company adopted certain amendments to the *Derivatives and Hedging* Topic of the Codification that changed the disclosure requirements for derivative instruments and hedging activities. Refer to Note 8 to our consolidated financial statements for additional information about the adoption of these amendments to the Codification.

For a more complete discussion of our accounting policies and procedures, see the notes to our consolidated financial statements.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

We are exposed to market risks arising from fluctuating prices of crude oil, natural gas and interest rates as discussed below. The Credit Agreement no longer requires us to maintain any derivative financial instruments. However, currently we are party to commodity option contracts, a commodity swap contract and an interest rate swap contract.

Commodity price risk. Our revenues, profitability and future rate of growth substantially depend upon market prices for oil and natural gas, which fluctuate widely. Oil and natural gas price declines and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. For example, assuming a 10% decline in our average realized oil and natural gas sales prices in 2009 and 2008, our loss before income taxes would have increased by approximately 23% in 2009 and 15% in 2008. If costs and expenses of operating our properties had increased by 10% in 2009 and 2008, our loss before income taxes would have increased by approximately 8% in 2009 and 3% in 2008.

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During the third quarter of 2009, we entered into commodity option contracts and a commodity swap contract to manage our exposure to commodity price risk from sales of oil and natural gas during the fiscal year ended December 31, 2010. As of December 31, 2009, our open commodity derivatives were as follows:

Zero Cost Collars Oil

Effective Date	Termination Date	Notional Quantity (Bbls)	Weighted Average NYMEX Contract Price Floor	Weighted Average NYMEX Contract Price Ceiling	Fair Value Liability (in thousands)
1/1/2010	3/31/2010	517,500	$ 69.01	$ 79.80	$ (1,802)
4/1/2010	6/30/2010	386,750	69.84	83.82	(1,163)
7/1/2010	9/30/2010	208,000	69.84	85.51	(707)
10/1/2010	12/31/2010	243,350	69.74	86.22	(1,032)
		1,355,600	$ 69.50	$ 82.98	$ (4,704)

Zero Cost Collars Natural Gas

Effective Date	Termination Date	Notional Quantity (MMBtu)	Weighted Average NYMEX Contract Price Floor	Weighted Average NYMEX Contract Price Ceiling	Fair Value Liability (in thousands)
2/1/2010	3/31/2010	2,905,500	$ 5.00	$ 5.94	$ (260)
4/1/2010	6/30/2010	3,380,500	5.00	6.14	(217)
7/1/2010	9/30/2010	1,545,500	5.00	6.60	(80)
10/1/2010	12/31/2010	1,831,800	5.00	8.35	(61)
		9,663,300	$ 5.00	$ 6.57	$ (618)

Swap Natural Gas

Effective Date	Termination Date	Notional Quantity (MMBtu)	Swap Price	Fair Value Liability (in thousands)
2/1/2010	12/31/2010	668,000	$ 5.71	$ (48)

While these contracts 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 the hedge. We do not enter into derivative instruments for speculative trading purposes. For additional details about these derivative contracts, refer to Note 8 to our consolidated financial statements.

Interest rate risk. As of December 31, 2009, we did not have any variable rate debt outstanding. However, we have elected to retain our interest rate swap to mitigate our exposure to interest rate fluctuations related to any future borrowings under the Credit Agreement. In accordance with the terms of our interest rate swap, we pay the counterparty the equivalent of a fixed interest payment and receive from the counterparty the equivalent of a floating interest payment based on a 3-month LIBOR. All interest rate swap payments are made quarterly and the LIBOR is determined in advance of each interest period. As of December 31, 2009, the total notional amount of the swap was $146.3 million. For additional details about this derivative contract, refer to Note 8 to our consolidated financial statements.

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Item 8. ***Financial Statements and Supplementary Data***

W&T OFFSHORE, INC. AND SUBSIDIARIES

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2009 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of

W&T Offshore, Inc. and Subsidiaries

We have audited W&T Offshore, Inc. and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). W&T Offshore, Inc. and subsidiaries management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, W&T Offshore, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2009 consolidated financial statements of W&T Offshore, Inc. and subsidiaries and our report dated March 1, 2010, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

March 1, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

W&T Offshore, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of income (loss), changes in shareholders equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of W&T Offshore, Inc. and subsidiaries at December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2009 the Company changed its method of calculating earnings per share as a result of the adoption of a new accounting standard and changed its reserve estimates and related disclosures as a result of adopting new oil and natural gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), W&T Offshore, Inc. and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2010, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

March 1, 2010

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 38,187	$ 357,552
Receivables:		
Oil and natural gas sales	54,978	36,550
Joint interest and other	51,312	83,178
Insurance	30,543	2,040
Income taxes	85,457	34,077
Total receivables	222,290	155,845
Prepaid expenses and other assets	28,777	30,417
Total current assets	289,254	543,814
Property and equipment at cost:		
Oil and natural gas properties and equipment (full cost method, of which $77,301 at December 31, 2009 and $99,139 at December 31, 2008 were excluded from amortization)	4,732,696	4,684,730
Furniture, fixtures and other	15,080	14,370
Total property and equipment	4,747,776	4,699,100
Less accumulated depreciation, depletion and amortization	3,752,980	3,217,759
Net property and equipment	994,796	1,481,341
Restricted deposits for asset retirement obligations	30,614	24,138
Deferred income taxes	5,117	
Other assets	7,052	6,893
Total assets	$ 1,326,833	$ 2,056,186
Liabilities and Shareholders Equity		
Current liabilities:		
Current maturities of long-term debt	$	$ 3,000
Accounts payable	115,683	228,899
Undistributed oil and natural gas proceeds	32,216	29,716
Asset retirement obligations	117,421	67,007
Accrued liabilities	13,509	18,254
Deferred income taxes	5,117	
Total current liabilities	283,946	346,876
Long-term debt, less current maturities net of discount	450,000	650,172
Asset retirement obligations, less current portion	231,379	480,890
Other liabilities	2,558	6,021
Commitments and contingencies		

Shareholders equity:		
Common stock, $0.00001 par value; 118,330,000 shares authorized; 77,579,968 issued and 74,710,795 outstanding at December 31, 2009; 76,291,408 issued and outstanding at December 31, 2008	1	1
Additional paid-in capital	373,050	372,595
Retained earnings	10,066	200,274
Treasury stock, at cost	(24,167)	
Accumulated other comprehensive loss		(643)
Total shareholders equity	358,950	572,227
Total liabilities and shareholders equity	$ 1,326,833	$ 2,056,186

See accompanying notes.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per share data)		
Revenues	$ 610,996	$ 1,215,609	$ 1,113,749
Operating costs and expenses:			
Lease operating expenses	203,922	229,747	234,758
Production taxes	1,544	8,827	5,921
Gathering and transportation	13,619	15,957	15,526
Depreciation, depletion and amortization	308,076	482,464	510,903
Asset retirement obligation accretion	34,461	39,312	22,007
Impairment of oil and natural gas properties	218,871	1,182,758	
General and administrative expenses	42,990	47,225	38,853
Derivative loss	7,372	16,464	36,532
Total costs and expenses	830,855	2,022,754	864,500
Operating income (loss)	(219,859)	(807,145)	249,249
Interest expense:			
Incurred	46,749	54,001	62,188
Capitalized	(6,662)	(19,292)	(25,100)
Loss on extinguishment of debt	2,926		2,806
Other income	842	13,372	6,404
Income (loss) before income tax expense (benefit)	(262,030)	(828,482)	215,759
Income tax expense (benefit)	(74,111)	(269,663)	71,459
Net income (loss)	$ (187,919)	$ (558,819)	$ 144,300
Basic and diluted earnings (loss) per common share	$ (2.51)	$ (7.36)	$ 1.89

See accompanying notes.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY

	Common Stock				Treasury Stock			
	Shares	Value	Additional Paid-In Capital	Retained Earnings	Shares	Value	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity
				(In thousands)				
Balances at December 31, 2006	75,900	$ 1	$ 361,855	$ 681,634		$	$ (573)	$ 1,042,917
Cash dividends:								
Common stock ($0.51 per share)				(39,131)				(39,131)
Share-based compensation			3,409					3,409
Restricted stock issued, net of forfeitures	336		2,229					2,229
Shares surrendered for payroll taxes	(61)		(1,826)					(1,826)
Net income				144,300				144,300
Other comprehensive loss, net of tax							(558)	(558)
Balances at December 31, 2007	76,175	1	365,667	786,803			(1,131)	1,151,340
Cash dividends:								
Common stock ($0.36 per share)				(27,710)				(27,710)
Share-based compensation			6,029					6,029
Restricted stock issued, net of forfeitures	178		1,731					1,731
Shares surrendered for payroll taxes	(62)		(832)					(832)
Net loss				(558,819)				(558,819)
Other comprehensive income, net of tax							488	488
Balances at December 31, 2008	76,291	1	372,595	200,274			(643)	572,227
Cash dividends:								
Common stock ($0.12 per share)			(6,861)	(2,289)				(9,150)
Share-based compensation			6,380					6,380
Restricted stock issued, net of forfeitures	1,471		3,014					3,014
Shares surrendered for payroll taxes	(182)		(2,078)					(2,078)
Net loss				(187,919)				(187,919)
Repurchase of common stock	(2,869)				2,869	(24,167)		(24,167)
Other comprehensive income, net of tax							643	643
Balances at December 31, 2009	74,711	$ 1	$ 373,050	$ 10,066	2,869	$ (24,167)	$	$ 358,950

See accompanying notes.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008 (In thousands)	2007
Operating activities:			
Net income (loss)	$ (187,919)	$ (558,819)	$ 144,300
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	345,637	521,776	532,910
Impairment of oil and natural gas properties	218,871	1,182,758	
Amortization of debt issuance costs and discount on indebtedness	1,838	2,749	6,472
Loss on extinguishment of debt	2,817		2,806
Share-based compensation related to restricted stock issuances	6,380	6,029	3,409
Unrealized derivative loss (gain)	693	(13,501)	37,831
Deferred income taxes	(346)	(249,445)	8,751
Other	998	833	1,006
Changes in operating assets and liabilities:			
Oil and natural gas receivables	(18,509)	77,017	(15,205)
Joint interest and other receivables	31,866	(35,885)	(22,356)
Insurance receivables	23,235		75,151
Income taxes	(52,100)	(46,930)	28,579
Prepaid expenses and other assets	(749)	4,917	477
Asset retirement obligations	(99,069)	(61,213)	(39,267)
Accounts payable and accrued liabilities	(117,230)	52,210	(76,199)
Other liabilities	(147)		(68)
Net cash provided by operating activities	156,266	882,496	688,597
Investing activities:			
Acquisition of property interest	(2,421)	(116,551)	
Proceeds from sales of oil and natural gas properties and equipment	32,226		1,859
Investment in oil and natural gas properties and equipment	(273,713)	(658,328)	(361,235)
Proceeds from insurance	6,916	5,828	
Purchases of furniture, fixtures and other, net	(705)	(4,812)	(711)
Net cash used in investing activities	(237,697)	(773,863)	(360,087)
Financing activities:			
Issuance of Senior Notes			450,000
Borrowings of other long-term debt	205,441		458,000
Repayments of long-term debt	(410,941)	(3,000)	(946,500)
Dividends to shareholders	(9,158)	(59,999)	(9,137)
Repurchases of common stock	(24,167)		
Debt issuance costs		(2,000)	(6,059)
Other	891	(132)	1
Net cash used in financing activities	(237,934)	(65,131)	(53,695)
Increase (decrease) in cash and cash equivalents	(319,365)	43,502	274,815
Cash and cash equivalents, beginning of period	357,552	314,050	39,235

Cash and cash equivalents, end of period	$ 38,187	$ 357,552	$ 314,050

See accompanying notes.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

Operations

W&T Offshore, Inc. and subsidiaries, referred to herein as W&T or the Company, is an independent oil and natural gas producer, active in the acquisition, exploitation, exploration and development of oil and natural gas properties in the Gulf of Mexico.

Basis of Presentation

Our consolidated financial statements include the accounts of W&T Offshore, Inc. and its majority owned subsidiaries. All significant intercompany transactions and amounts have been eliminated for all years presented.

Reclassifications

Certain reclassifications have been made to prior periods financial statements to conform to the current presentation.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting periods and the reported amounts of proved oil and natural gas reserves. Actual results could differ from those estimates.

Cash Equivalents

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

Revenue Recognition

We recognize oil and natural gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectiblity is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties in which there is joint ownership. Under this method, we record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which the Company has taken less than its ownership share of production. At December 31, 2009 and 2008, $6.5 million and $7.0 million, respectively, was included in current liabilities related to natural gas imbalances.

Concentration of Credit Risk

Our customers are primarily large integrated oil and natural gas companies and large financial institutions. Our production is sold utilizing month-to-month contracts that are based on prevailing prices. The Company attempts to minimize credit risk exposure to purchasers of the Company s oil and natural gas through formal credit policies, monitoring procedures, and letters of credit or guaranties when considered necessary. We historically have not had any significant problems collecting our receivables, except in rare circumstances. Accordingly, we do not maintain an allowance for doubtful accounts.

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

	Year Ended December 31,		
	2009	2008	2007
Customer			
Shell Trading (US) Co.	34%	33%	31%
J.P. Morgan Ventures Energy Corp.	15%	**	**
Chevron Corp.	13%	19%	11%
ConocoPhillips	**	**	17%

** less than 10%

We believe that the loss of any of the customers above would not result in a material adverse effect on our ability to market future oil and natural gas production.

Properties and Equipment

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

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

We capitalize interest on expenditures made in connection with the exploration and development of unproved properties that are excluded from the amortization base. Interest is capitalized only for the period that exploration and development activities are in progress. We capitalized $6.7 million, $19.3 million and $25.1 million of interest expense during the years ended December 31, 2009, 2008 and 2007, respectively.

Oil and natural gas properties included in the amortization base are amortized using the units-of-production method based on production and estimates of proved reserve quantities. In addition to costs associated with evaluated properties and capitalized asset retirement obligations, the amortization base includes estimated future development costs to be incurred in developing proved reserves as well as estimated plugging and abandonment costs, net of salvage value, that have not yet been capitalized as asset retirement costs.

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

Under the full cost method of accounting, we are required to periodically perform a ceiling test, which determines a limit on the book value of our oil and natural gas properties. If the net capitalized cost of oil and

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natural gas properties (including capitalized asset retirement obligations), net of related deferred income taxes, exceeds the present value of estimated future net revenues from proved reserves discounted at 10%, plus the cost of unproved oil and natural gas properties not being amortized, plus the lower of cost or estimated fair value of unproved oil and natural gas properties included in the amortization base, net of related tax effects, the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization. Any such write downs are not recoverable or reversible in future periods. Estimated future net revenues used in the ceiling test as of December 31, 2009 are based on the unweighted average of first-day-of-the-month commodity prices over the period January 2009 through December 2009 and exclude future cash outflows related to capitalized asset retirement obligations and include future development costs and asset retirement obligations related to wells to be drilled. Primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008, we recorded a ceiling test impairment at December 31, 2008 of $1.2 billion. Additionally, we recorded a ceiling test impairment at March 31, 2009 of $218.9 million primarily as a result of a further decline in natural gas prices as of March 31, 2009. Declines in oil and natural gas prices after December 31, 2009 may require us to record additional ceiling test impairments in the future. We did not have a ceiling test impairment during the year ended December 31, 2007.

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

Oil and Natural Gas Reserve Information

In January 2010, the Financial Accounting Standards Board (FASB) issued certain amendments to the *Extractive Activities Oil and Gas* Topic of the Accounting Standards Codification (the Codification) that updated and aligned the FASB s reserve estimation and disclosure requirements for oil and natural gas companies with the reserve estimation and disclosure requirements that were adopted by the Securities and Exchange Commission (SEC) in December 2008. The FASB s amendments and the SEC s new requirements became effective for annual reporting periods ending on or after December 31, 2009. Collectively, the new rules permit the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of *proved reserves* which was changed to indicate, among other things, that commencing with year-end 2009 entities must use unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than end-of-period commodity prices, when estimating quantities of proved reserves. Similarly, the prices used to calculate the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future cash flows have been changed from end-of-period commodity prices to the 12-month average commodity prices used in calculating proved reserves. Beginning in the fourth quarter of 2009, the estimated future net revenues used to calculate the ceiling test are based on the 12-month average commodity price for each product. Also, because it is our policy to use end-of-period reserves in the determination of quarterly depletion, our depreciation, depletion, amortization and accretion (DD&A) expense for the fourth quarter of 2009 was calculated using proved reserves at December 31, 2009 that were determined in accordance with the new rules. Additionally, entities must separately disclose information about reserve quantities and certain financial statement amounts for geographic areas that represent 15 percent or more of proved reserves, and equity-method investees should be included in determining whether an entity has significant oil and gas producing activities. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, 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. Refer to Note 20 for additional information about our proved reserves and the impact of the new reserve estimation and disclosure requirements.

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Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and interest rates. We use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our credit facility. Our derivative instruments currently consist of commodity option contracts, a commodity swap contract and an interest rate swap contract. We do not enter into derivative instruments for speculative trading purposes.

We account for derivative contracts in accordance with the *Derivatives and Hedging* Topic of the Codification, which requires each derivative to be recorded on the balance sheet as an asset or a liability at its fair value. Changes in a derivative s fair value are required to be recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is entered into.

During the years ended December 31, 2009, 2008 and 2007, changes in the fair value of our commodity derivative contracts were recognized currently in earnings. In 2007, we terminated one of our interest rate swap contracts and de-designated the remaining interest rate swap contract as a cash flow hedge. From the dates of de-designation, subsequent changes in the fair value of our interest rate swap were immediately recognized in earnings.

Fair Value of Financial Instruments

We include fair value information in the notes to consolidated financial statements when the fair value of our financial instruments is different from the book value. We believe that the book value of our cash and cash equivalents, receivables, accounts payable and accrued liabilities materially approximates fair value due to the short-term nature and the terms of these instruments.

Effective January 1, 2008, we adopted the provisions of the *Fair Value Measurements and Disclosures* Topic of the Codification on a prospective basis for all of our financial assets and liabilities that are required to be measured at fair value. In February 2008, the FASB granted a one-year deferral of the provisions of this Topic for certain non-financial assets and liabilities and, as a result, effective January 1, 2009, our asset retirement obligations incurred are initially measured at fair value in accordance with the *Fair Value Measurements and Disclosures* Topic of the Codification. The adoption of the provisions of this Topic did not have a material impact on our financial statements.

Income Taxes

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

Deferred Financing Costs

Debt issuance costs associated with our revolving loan facility are amortized using the straight-line method over the scheduled maturity of the debt. Debt issuance costs and debt premiums or discounts associated with all other debt are deferred and amortized over the scheduled maturity of the debt utilizing the effective interest method.

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Share-Based Compensation

In accordance with the *Compensation Stock Compensation* Topic of the Codification, compensation cost for share-based payments to employees and non-employee directors is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which the recipient is required to provide service in exchange for the award.

Earnings (Loss) Per Share

In accordance with the *Earnings Per Share* Topic of the Codification, effective January 1, 2009, the Company adopted certain amendments to the accounting principles relating to its calculation of earnings (loss) per share. The amendments provide that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share under the two-class method. For additional information about the impact of the adoption of these amendments to the Codification on our financial statements, refer to Note 16.

Recent Accounting Developments

In addition to the amendments to the *Extractive Activities Oil and Gas* Topic of the Codification that were previously discussed, the following recent accounting developments are applicable to the Company.

In April 2009, the FASB issued certain amendments to the *Financial Instruments* Topic of the Codification that require public companies to include disclosures about the fair value of their financial instruments in interim reporting periods, as well as the methods, significant assumptions and any changes in such methods and assumptions used to estimate the fair value of financial instruments. These amendments became effective for interim reporting periods ending after June 15, 2009. The adoption of these amendments to the Codification did not have a material impact on the Company s financial statements.

Effective January 1, 2009, the Company adopted certain amendments to the *Business Combinations* Topic of the Codification that require the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree to be measured at their respective fair values at the acquisition date. These amendments require the acquirer to record the fair value of contingent consideration (if any) at the acquisition date. Acquisition-related costs incurred prior to an acquisition are required to be expensed rather than included in the purchase-price determination. Also included in the amendments are guidance for recognizing and measuring the goodwill acquired in a business combination and guidance for determining what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of a business combination. These amendments apply prospectively to business combinations for which the acquisition date is on or after January 1, 2009. We expect these amendments will have an impact on our consolidated financial statements, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of acquisitions, if any, that we may consummate in the future.

Effective January 1, 2009, the Company adopted certain amendments to the *Consolidation* Topic of the Codification that establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. The adoption of these amendments to the Codification did not have a material impact on the Company s financial statements.

Effective January 1, 2009, the Company adopted certain amendments to the *Derivatives and Hedging* Topic of the Codification that changed the disclosure requirements for derivative instruments and hedging activities. Refer to Note 8 for additional information about the adoption of these amendments to the Codification.

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2. Asset Retirement Obligations

Pursuant to the *Asset Retirement and Environmental Obligations* Topic of the Codification, an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset is required to be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset. Asset retirement obligations incurred after December 31, 2008 are initially measured at fair value in accordance with the *Fair Value Measurements and Disclosures* Topic of the Codification. The fair value of the ARO is measured using expected cash outflows associated with the ARO, discounted at our credit-adjusted risk-free rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

The following is a reconciliation of our asset retirement obligation liability as of December 31, 2009 and 2008 (in thousands).

	2009	2008
Asset retirement obligation, beginning of period	$ 547,897	$ 458,681
Liabilities settled	(99,069)	(61,213)
Accretion of discount	34,461	39,312
Disposition of properties	(128,467)	
Liabilities assumed through acquisition	12,816	2,574
Liabilities incurred	343	2,314
Revisions of estimated liabilities due to Hurricane Ike	77,271	36,962
Revisions of estimated liabilities all other	(96,452)	69,267
Asset retirement obligation, end of period	348,800	547,897
Less current portion	117,421	67,007
Long-term	$ 231,379	$ 480,890

Each year (or more often if conditions warrant) we review and, to the extent necessary, revise our asset retirement obligation estimates. In 2009, we reduced our asset retirement obligations by $99.1 million for work performed to settle our liabilities (including $51.9 million to plug and abandon wells and facilities damaged by Hurricane Ike) and by $128.5 million for asset dispositions. In addition, we decreased our estimates of future asset retirement obligations by $96.5 million, a portion of which relates to useful life extensions while the remainder primarily relates to recent cost reductions we experienced in the marketplace for decommissioning, site clearance and removal of certain of our operated structures and pipelines. Conversely, our estimated asset retirement obligations increased by $12.8 million related to additional interests we acquired in certain fields during the fourth quarter of 2009 and by $77.2 million, the majority of which relates to revised estimates for the dismantlement of two operated platforms that were toppled during Hurricane Ike and the plugging and abandonment of the associated wells. The remainder of the increase relates to revised estimates related to other wells and facilities damaged by such storm.

During 2008, the Company revised, among other things, its estimate of the cost to decommission its sub-sea wells and made other changes to the estimated timing and amounts of settlements. Also included in our revisions of estimated liabilities for 2008 is an approximate $37.0 million increase in estimated settlements as a result of damage to our facilities caused by Hurricane Ike in the third quarter of 2008. See Note 12 for additional details about the impact of Hurricane Ike on our financial statements.

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3. Restricted Deposits

Restricted deposits as of December 31, 2009 and 2008 consisted of funds escrowed for the future plugging and abandonment of certain oil and natural gas properties. In connection with additional interests we acquired in certain fields during the fourth quarter of 2009, we received $6.5 million from the previous operator to cover future asset retirement obligations for those fields. We are not obligated to contribute additional amounts to these escrowed accounts.

4. Significant Acquisitions and Divestitures

In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. In connection with these transactions, we reduced our asset retirement obligations by approximately $128.5 million and we received proceeds of approximately $32.2 million.

On December 21, 2007, we entered into an agreement with Apache Corporation (Apache) to acquire its interest in Ship Shoal 349 field for $116.6 million in cash. This field is located off the coast of Louisiana and covers two federal offshore lease blocks, Ship Shoal blocks 349 and 359. The transaction closed on January 29, 2008, with an effective date of January 1, 2008. The acquisition increased our working interest in this field to 100% from approximately 59%, and the estimated proved oil and natural gas reserves acquired were 60.5 Bcfe. This acquisition was funded from cash on hand.

5. Equity Structure and Transactions

As of December 31, 2009 and 2008, the Company was authorized to issue two million shares of preferred stock with a par value of $0.00001 per share; however, no preferred shares have been issued or were outstanding as of the respective dates.

In March 2009, we announced by press release a $25 million stock repurchase program, which expired on December 31, 2009. Under the program, shares could be purchased from time to time at prevailing prices in the open market, in block transactions, in privately negotiated transactions or accelerated share repurchase programs through December 31, 2009, in accordance with Rule 10b-18 under the Securities Exchange Act of 1934 (the Exchange Act). In 2009, we purchased 2,869,173 shares of our common stock for approximately $24.2 million in the open market in accordance with the repurchase program. Repurchases were funded with cash on hand.

During the three years ended December 31, 2009, we paid regular cash dividends of $0.12 per common share per year. Additionally, on January 11, 2008, we paid a special cash dividend of $30.0 million, or approximately $0.39 per common share, to shareholders of record on December 21, 2007, and on December 22, 2008, we paid a special cash dividend of $20.84 million, or approximately $0.2729 per common share, to shareholders of record on December 1, 2008. On February 24, 2010, our board of directors declared a cash dividend of $0.03 per common share, payable on March 27, 2010 to shareholders of record on March 12, 2010.

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6. Long-Term Debt

As of December 31, 2009 and 2008 our long-term debt was as follows (in thousands):

	December 31, 2009	December 31, 2008
Tranche B term loan facility, net of unamortized discount of $2,328 at December 31, 2008	$	$ 203,172
8.25% Senior notes, due June 2014	450,000	450,000
Total long-term debt	450,000	653,172
Current maturities of long-term debt		(3,000)
Long-term debt, less current maturities	$ 450,000	$ 650,172

At December 31, 2009 and 2008, the estimated fair value of our Senior notes was approximately $432 million and $225 million, respectively, and at December 31, 2008, the estimated fair value of our Tranche B term loan facility was approximately $186 million, based on quoted prices.

Aggregate annual maturities of long-term debt as of December 31, 2009 are as follows (in millions): 2010 $0.0; 2011 $0.0; 2012 $0.0; 2013 $0.0; 2014 $450.0; thereafter $0.0.

Private Offering of 8.25% Senior Notes due 2014

In June 2007, the Company sold and issued to eligible investors $450.0 million aggregate principal amount of 8.25% senior notes due 2014 (the Notes) pursuant to Rule 144A under the Securities Act of 1933, as amended. Net proceeds generated by the offering were approximately $444.6 million after underwriting fees of $4.1 million and legal, accounting, printing and various other fees of approximately $1.3 million. The Company used substantially all of the net proceeds from the private placement of the Notes to repay a portion of the outstanding borrowings under the Third Amended and Restated Credit Agreement, as amended (the Credit Agreement).

The Notes bear interest at a fixed rate of 8.25%, with interest payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the Notes is 8.4%.

The Company and its restricted subsidiaries are subject to certain covenants under the indenture governing the Notes which limit the Company s and each of its restricted subsidiaries ability to, among other things, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of its assets, engage in transactions with affiliates, pay dividends or make other distributions on capital stock or subordinated indebtedness and create unrestricted subsidiaries.

Credit Agreement

The Credit Agreement is a secured facility that is collateralized by our oil and natural gas properties. Availability under the Credit Agreement is subject to a semi-annual borrowing base redetermination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their valuation of our proved reserves and their own internal criteria. In April 2009, our lenders reduced the borrowing base from $710.0 million to $405.5 million. In November 2009, our borrowing base of $405.5 million was reaffirmed by our lenders. Any determination by our lenders to reduce our borrowing base will cause a similar reduction in the availability under our revolving loan facility.

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In June 2007, the Company used proceeds from the Notes to pay in full the Tranche A term loan facility outstanding balance of $50.0 million and to make a payment of $90.0 million on the Tranche B term loan facility balance outstanding. The Company also used proceeds from the Notes to pay the revolving loan facility balance then outstanding of $271.0 million. During the year ended December 31, 2007, we recorded a loss of $2.8 million related to the write-off of all the deferred financing costs related to the Tranche A term loan facility and a pro-rata portion of the deferred financing costs related to the Tranche B term loan facility.

On July 24, 2008, certain amendments were made to the Credit Agreement, including an amendment to extend the maturity of the revolving loan facility under the Credit Agreement to July 23, 2012 and increase the interest margin. Other amendments have subsequently been made to the Credit Agreement, including amendments related to share repurchases, dividends and interest margins.

During the first quarter of 2009, we made a principal payment of $0.8 million on our Tranche B term loan facility. In May 2009, the Company paid in full the Tranche B term loan facility outstanding balance of $204.75 million, plus accrued and unpaid interest of $0.7 million, with borrowings under the revolving loan facility. In June 2009, we repaid $62.9 million of borrowings under the revolving loan facility, and in December 2009, we repaid the remaining amount outstanding under the revolving loan facility of $142.5 million. Both of these debt repayments were funded with cash on hand. During the year ended December 31, 2009, we recorded a loss of $2.9 million related to the write-off of all the deferred financing costs related to the Tranche B term loan facility and the write-off of a portion of the deferred financing costs related to the revolving loan facility, as well as the incurrence of other incidental costs in connection with the payoff of the Tranche B term loan facility. The Credit Agreement provides for the availability of letters of credit for up to $90.0 million, provided however, that its usage is subject to availability under the revolving loan. At December 31, 2009, we had $0.7 million of letters of credit outstanding and our remaining availability under the revolving loan facility was $404.8 million. In January 2010, we borrowed $142.5 million under our revolving loan facility.

Effective May 4, 2009, borrowings under the revolving loan facility bear interest at either (1) the highest of the Prime Rate, the Federal Funds Rate plus 0.50%, or the one-month Eurodollar Rate plus 1.0%, plus a margin which varies from 0.75% to 1.75% depending on the level of total borrowings under the Credit Agreement, or (2) to the extent the loan outstanding is designated as a Eurodollar loan, at the London Interbank Offered Rate (LIBOR) plus a margin that varies from 2.0% to 3.0% depending on the level of total borrowings under the Credit Agreement. The Credit Agreement also bears an unused commitment fee of 0.50%. The estimated effective interest rate on the revolving loan facility, including unused commitment fees and amortization of deferred financing costs, was 4.8% during the year ended December 31, 2009.

The Credit Agreement contains covenants that restrict the payment of cash dividends and share repurchases (currently limited to $60.0 million per year), borrowings other than from the facilities, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. We are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio, as such ratios are defined in the Credit Agreement. In connection with the April 2009 borrowing base redetermination, we amended the maximum leverage ratio, which is the ratio of total debt to EBITDA (as those terms are defined in the Credit Agreement), to be 3.75 to 1 for the four quarters ended September 30, 2009, 3.50 to 1 for the four quarters ended December 31, 2009, 3.25 to 1 for the four quarters ended March 31, 2010 and 3.00 to 1 thereafter. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2009.

7. Fair Value Measurements

Effective January 1, 2008, we adopted the provisions of the *Fair Value Measurements and Disclosures* Topic of the Codification on a prospective basis. This Topic establishes a framework for measuring fair value under generally

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accepted accounting principles (GAAP), clarifies the definition of fair value within that framework, and expands disclosures about the use of fair value measurements. This Topic does not require any new fair value measurements under GAAP. In February 2008, the FASB granted a one-year deferral of the provisions of this Topic for certain non-financial assets and liabilities, and accordingly, effective January 1, 2009, our asset retirement obligations incurred are initially measured at fair value in accordance with the *Fair Value Measurements and Disclosures* Topic of the Codification.

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

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

Level 1 quoted prices in active markets for identical assets or liabilities.

Level 2 inputs other than quoted prices that are observable for an asset or liability. These include: quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).

Level 3 unobservable inputs that reflect the Company s own expectations about the assumptions that market participants would use in measuring the fair value of an asset or liability.

We measure the fair value of our derivative financial instruments by applying the income approach, using inputs that are classified within Level 2 of the valuation hierarchy. The fair values of our derivative assets and liabilities include adjustments for credit risk and were $0.1 million and $9.9 million, respectively, at December 31, 2009. The fair value of our derivative liability was $9.1 million at December 31, 2008. For additional details about our derivative financial instruments, refer to Note 8. As disclosed in Note 6, the estimated fair value of the Notes was approximately $432 million and $225 million at December 31, 2009 and 2008, respectively, and the estimated fair value of our Tranche B term loan facility was approximately $186 million at December 31, 2008, based on quoted prices, which are classified as level 1 inputs. The impact of the adoption of the *Fair Value Measurements and Disclosures* Topic of the Codification on our financial position and results of operations was immaterial.

8. Derivative Financial Instruments

We account for derivative contracts in accordance with the *Derivatives and Hedging* Topic of the Codification, which requires each derivative to be recorded on the balance sheet as an asset or a liability at its fair value. Changes in a derivative s fair value are required to be recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is entered into.

Effective January 1, 2009, the Company adopted certain amendments to the *Derivatives and Hedging* Topic of the Codification which changed the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative

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instruments; (b) how derivative instruments and related hedged items are accounted for; and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. These amendments to the Codification did not have an impact on the Company s financial position, results of operations or cash flows upon adoption.

Our market risk exposure relates primarily to commodity prices and interest rates. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our credit facility. We do not enter into derivative instruments for speculative trading purposes. Our derivative instruments currently consist of commodity option contracts, a commodity swap contract and an interest rate swap contract. The Company is exposed to credit loss in the event of nonperformance by the counterparties; however, none is currently anticipated.

We measure the fair value of our derivatives by applying the income approach, using inputs that are classified within Level 2 of the valuation hierarchy. The fair values of our derivative assets and liabilities include adjustments for credit risk and were $0.1 million and $9.9 million, respectively, at December 31, 2009. The fair value of our derivative liability was $9.1 million at December 31, 2008.

Commodity Derivatives

As of December 31, 2008, we did not have any open commodity derivative positions. During the third quarter of 2009, we entered into commodity option contracts and a commodity swap contract to manage our exposure to commodity price risk from sales of oil and natural gas during the fiscal year ended December 31, 2010. We have elected not to designate our commodity derivatives as hedging instruments. While these contracts are intended to reduce the effects of volatile oil and natural gas prices, they may also limit future income from favorable price movements. As of December 31, 2009, our open commodity derivatives were as follows:

Zero Cost Collars Oil

Effective Date	Termination Date	Notional Quantity (Bbls)	Weighted Average NYMEX Contract Price Floor	Weighted Average NYMEX Contract Price Ceiling	Fair Value Liability (in thousands)
1/1/2010	3/31/2010	517,500	$ 69.01	$ 79.80	$ (1,802)
4/1/2010	6/30/2010	386,750	69.84	83.82	(1,163)
7/1/2010	9/30/2010	208,000	69.84	85.51	(707)
10/1/2010	12/31/2010	243,350	69.74	86.22	(1,032)
		1,355,600	$ 69.50	$ 82.98	$ (4,704)

Zero Cost Collars Natural Gas

Effective Date	Termination Date	Notional Quantity (MMBtu)	Weighted Average NYMEX Contract Price Floor	Weighted Average NYMEX Contract Price Ceiling	Fair Value Liability (in thousands)
2/1/2010	3/31/2010	2,905,500	$ 5.00	$ 5.94	$ (260)
4/1/2010	6/30/2010	3,380,500	5.00	6.14	(217)
7/1/2010	9/30/2010	1,545,500	5.00	6.60	(80)
10/1/2010	12/31/2010	1,831,800	5.00	8.35	(61)
		9,663,300	$ 5.00	$ 6.57	$ (618)

Effective Date	Termination Date	Swap Natural Gas Notional Quantity (MMBtu)	Swap Price	Fair Value Liability (in thousands)
2/1/2010	12/31/2010	668,000	$ 5.71	$ (48)

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Changes in the fair value of our commodity derivative contracts are recognized currently in earnings. Our derivative loss for the year ended December 31, 2009 includes realized and unrealized losses of $0.2 million and $5.4 million, respectively, related to our commodity derivatives. Our derivative loss for the year ended December 31, 2008 includes a realized loss of $27.4 million related to commodity derivatives offset by a gain of $17.4 million related to a change in the fair value of such derivatives. Our derivative loss for the year ended December 31, 2007 includes an unrealized loss of $34.3 million related to commodity derivatives offset by a realized gain of $1.3 million related to such derivatives.

At December 31, 2009, $0.1 million was included in prepaid expenses and other assets and $5.5 million was included in accrued liabilities related to our commodity derivative contracts.

Interest Rate Swap

We have one interest rate swap outstanding with a fixed interest rate of 5.21%. Initially, this swap was designated as a hedge of the floating-rate interest payments on our Tranche B term loan facility. However, as a result of payments on the loan and changes to the swap contract, hedge accounting was discontinued completely in 2007. Changes in fair value subsequent to the discontinuation of hedge accounting have been immediately recognized in earnings. During 2007, 2008 and most of 2009 there continued to be amounts outstanding under the Tranche B term loan facility, and consequently, we have been recognizing in earnings the amounts that remained in accumulated other comprehensive income upon de-designation of our interest rate swap as a cash flow hedge. As a result of the full repayment of our Tranche B term and revolving loan facilities in 2009, the remaining accumulated other comprehensive loss of approximately $0.2 million was immediately recognized in earnings through interest expense in December 2009. As of December 31, 2009, the total notional amount of our swap was $146.3 million.

During the year ended December 31, 2009, we recorded an unrealized loss of $1.8 million related to our interest rate swap. During the year ended December 31, 2008, we recorded realized and unrealized losses of $2.6 million and $3.9 million, respectively, in earnings related to our interest rate swap. During the year ended December 31, 2007, we recorded an unrealized loss of $3.5 million in earnings related to our interest rate swaps. The realized gain on our interest rate swaps during the year ended December 31, 2007 was not material. For the year ended December 31, 2007, no amount was recognized in earnings due to ineffectiveness related to our interest rate swaps.

At December 31, 2009, the fair value of our interest rate swap was $4.4 million, all of which was included in accrued liabilities. At December 31, 2008, the fair value of our interest rate swap was $9.1 million, of which $5.7 million was included in accrued liabilities and $3.4 million was included in other liabilities, representing the current and non-current portions, respectively.

9. Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Current federal	$ (74,038)	$ (20,356)	$ 62,708
Current state	(73)	138	
Deferred federal		(249,445)	8,751
	$ (74,111)	$ (269,663)	$ 71,459

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Effective Tax Rate Reconciliation

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

	Year Ended December 31,					
	2009		2008		2007	
Income tax expense (benefit) at the federal statutory rate	$ (91,710)	35.0%	$ (289,969)	35.0%	$ 75,516	35.0%
Share-based compensation	208		1,214	(0.2)		
Domestic production activities deduction	3,167	(1.2)	1,048	(0.2)	(4,116)	(1.9)
State income taxes	(73)		138			
Other	(297)	0.1	515		59	
Valuation allowance	14,594	(5.6)	17,391	(2.1)		
	$ (74,111)	28.3%	$ (269,663)	32.5%	$ 71,459	33.1%

Our effective tax rate for the year ended December 31, 2009 primarily reflects recapture of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code related to net operating loss carrybacks for tax purposes as well as the incremental current period effect of a change in our valuation allowance for our deferred tax assets. Our effective tax rate for the year ended December 31, 2008 primarily reflects the effect of a valuation allowance for our deferred tax assets. Our effective tax rate for the year ended December 31, 2007 reflects the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code. In 2009 and 2008, the Company experienced a net operating loss for tax purposes and as a result, the qualified domestic production activities deduction was not available to us. In 2009 a portion of the qualified domestic production activities deduction for 2005 and 2007 was recaptured due to carrybacks of a net operating loss in 2009 to 2005 and 2007. Additionally, in 2008 a portion of the qualified domestic production activities deduction for 2007 was recaptured due to a carryback of the net operating loss in 2008 to 2007.

Deferred Tax Assets and Liabilities

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

	December 31,	
	2009	2008
Deferred tax liabilities:		
Property and equipment	$	$
Other	5,641	3,598
Total deferred tax liabilities	5,641	3,598
Deferred tax assets:		
Derivatives	2,827	2,930
Minimum tax credit	23,576	

State net operating loss	3,483	2,627
Property and equipment	9,125	13,846
Other	2,098	4,213
Valuation allowance	(35,468)	(20,018)
Total deferred tax assets	5,641	3,598
Net deferred tax liabilities	$	$

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On November 6, 2009, the Worker, Homeownership and Business Assistance Act of 2009 was signed into law. A provision of this act provides an election to increase the carryback period for applicable net operating losses up to five years from two years. A tax benefit of $38.4 million was recorded during the fourth quarter of 2009 as a result of this legislation.

During the year ended December 31, 2009, we recorded a ceiling test impairment of $218.9 million, which resulted in a deferred tax asset balance related to our oil and gas properties and equipment. Additionally, we recorded a minimum tax credit of $23.6 million resulting in a deferred tax asset which was fully offset by a valuation allowance. At December 31, 2009, we had a federal income tax receivable of $85.5 million. This amount is comprised principally of a net operating loss carryback from 2008 to 2007 of $8.9 million and a net operating loss carryback from 2009 to 2004, 2005, and 2007 of $22.1 million, $40.0 million and $14.1 million, respectively.

During the year ended December 31, 2008, we recorded a ceiling test impairment of $1.2 billion, which resulted in a deferred tax asset balance related to our oil and gas properties and equipment. This balance was fully offset by a valuation allowance. At December 31, 2008, we had a federal income tax receivable of $34.1 million. This amount is comprised of estimated federal tax payments deposited in 2008 of $17.7 million (refunded in the first quarter of 2009) and a net operating loss carryback to 2007 of $16.4 million.

Net Operating Loss and Tax Credit Carryovers

The table below presents the details of our net operating loss and tax credit carryovers as of December 31, 2009 (in thousands):

	Amount	Expiration Year
State net operating loss	$ 3,483	2021-2025
Minimum tax credit	23,576	Indefinite
General business credit	406	2027-2028

Valuation Allowance

Deferred tax assets are recorded on net operating losses, minimum tax credits and temporary differences in the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. Minimum tax credits are attributable to net minimum tax paid in prior years as a result of net operating loss carrybacks from 2009 to prior years. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. As part of our assessment, we consider future reversals of existing taxable temporary differences. A valuation allowance offsets substantially all of our deferred tax assets at December 31, 2009 and 2008.

Uncertain Tax Positions

We do not have any unrecognized tax benefits as of December 31, 2009 and 2008. As of December 31, 2009 and 2008, we do not have any accrued interest or penalties related to uncertain tax positions; however, when applicable, we will recognize interest and penalties related to uncertain tax positions in income tax expense. The tax years from 2006 through 2009 remain open to examination by the tax jurisdictions to which we are subject.

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10. Commitments

We have operating lease agreements for office space and office equipment, which terminate in August 2013. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2009 are as follows (in millions): 2010 $2.0; 2011 $2.0; 2012 $0.3; 2013 $0.1; 2014 $0.0; thereafter $0.0.

Total rent expense was approximately $2.2 million, $2.1 million and $2.5 million during the years ended December 31, 2009, 2008 and 2007, respectively.

11. Contingent Liabilities

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

12. Hurricane Remediation and Insurance Claims

During the third quarter of 2008, Hurricane Ike, and to a much lesser extent Hurricane Gustav, caused property damage and disruptions to our exploration and production activities. We currently have insurance coverage for named windstorms but we do not carry business interruption insurance. Our insurance policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention of $10 million per occurrence that must be satisfied by us before we are indemnified for losses. In the fourth quarter of 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. Our insurance coverage policy limits at the time of Hurricane Ike were $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The damage we incurred as a result of Hurricane Gustav was well below our retention amount.

Below is a summary of remediation costs related to Hurricanes Ike and Gustav that were included in lease operating expenses during the years ended December 31, 2009 and 2008 (in thousands):

	Year Ended December 31, 2009	Year Ended December 31, 2008
Incurred	$ 37,062	$ 19,764
Less amounts approved for payment under our insurance policies	(18,683)	(2,040)
Included in lease operating expenses	$ 18,379	$ 17,724

As discussed in further detail below, included in lease operating expenses for the year ended December 31, 2007 is $18.5 million for remediation costs related to Hurricanes Katrina and Rita that were not covered by insurance.

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We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection. Our assessment of probability considers the review and approval of such costs by our insurance underwriters adjuster. Claims that have been processed in this manner have been paid on a timely basis.

To the extent our insurance underwriters adjuster has reviewed work plans and other information provided by us in connection with our plugging and abandonment activities scheduled to be completed and that were accelerated by Hurricane Ike, and has indicated that our insurance policies provide coverage for such costs and they are within policy limits, we have recognized an insurance receivable. See Note 2 for additional information about the impact of Hurricane Ike on our asset retirement obligations.

Below is a reconciliation of our insurance receivables from December 31, 2008 to December 31, 2009 (in thousands):

Balance, December 31, 2008	$ 2,040
Costs approved under our insurance policies:	
Capital (1)	6,916
Remediation	18,683
Plugging and abandonment	22,880
Costs expected to be approved under our insurance policies:	
Dismantlement and removal of two toppled platforms	28,858
Payments received:	
Capital (1)	(6,916)
Remediation	(19,417)
Plugging and abandonment	(22,501)
Balance, December 31, 2009	$ 30,543

(1) Includes a $1.7 million indemnity for well control costs incurred in connection with one of the development wells we drilled in 2009.

At December 31, 2009, $1.3 million of remediation costs and $29.2 million related to the plugging and abandonment of wells and dismantlement of facilities damaged by Hurricane Ike are included in insurance receivables. We expect that our available cash and cash equivalents, cash flow from operations and the availability under our credit facility will be sufficient to meet any necessary expenditures that may exceed our insurance coverage for damages incurred as a result of Hurricanes Ike and Gustav.

In March 2007, we entered into agreements with our insurance underwriters to settle all claims related to Hurricanes Katrina and Rita, as well as a claim to recover drilling costs on a well at Green Canyon 82 that experienced uncontrollable water flow in the second quarter of 2006. After adjustments for applicable deductibles and reimbursements of $21.9 million received in 2006 and $4.8 million received in February 2007, the Company received proceeds of $73.3 million in March 2007. Total reimbursements of $78.1 million received in the first quarter of 2007 exceeded our insurance receivables at December 31, 2006 by $2.9 million. Such amount was used to offset a portion of our hurricane remediation costs incurred in 2007, which totaled $25.2 million. In the third quarter of 2007, we recovered $3.8 million under the insurance policy of one of our partners, which also offset a portion of our hurricane remediation costs incurred in 2007. Included in lease operating expenses for the year ended December 31, 2007 is $18.5 million for hurricane remediation expenses that were not covered by insurance.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Long-Term Incentive Compensation

The Company maintains a long-term incentive compensation plan (the Compensation Plan). The key metrics for determining awards, which may be in the form of stock options, stock appreciation rights, restricted stock or performance shares, are reserve and production growth, lease operating cost containment and general and administrative cost containment. The Compensation Plan may be terminated by executive management or the board of directors at any time without incurring additional obligations for grants.

As part of the Compensation Plan, the Company has an Annual Incentive Plan (as amended, the Plan) that covers all employees of the Company except those executive officers who, by written agreement, have elected in the past not to participate (our Chief Executive Officer and our Secretary). Under the Plan, eligible employees earn cash bonuses and awards of restricted stock from a bonus pool. The bonus pool consists of five percent of pre-tax income, which may be adjusted for extraordinary or unusual items or events (such as a ceiling test impairment), as determined by the Compensation Committee of the board of directors in its sole discretion. Awards of restricted stock are issued pursuant to, and are subject to, the terms of the Plan.

Awards under the Plan consist of a general award and an extraordinary performance award. Each type of award includes a cash component and a restricted stock component and such components are based on pre-determined percentages of an employee s base salary. However, the extraordinary performance portion is paid only if the Company achieves certain performance goals, which may be adjusted by the Compensation Committee of the board of directors for extraordinary or unusual items or events. Shares of restricted stock awarded under the Plan generally vest in three equal installments with the first such installment vesting in December of the year in which the shares are granted and annually thereafter. Only those eligible employees who are employed by the Company on the date an award is paid under the Plan are entitled to receive such award.

Pursuant to the terms of the Plan, in 2009 we did not meet any of the prerequisites and therefore the Compensation Committee and the Board of Directors determined that no awards were payable for 2009. For 2008, the bonus pool was equal to the amount necessary to pay 100% of the general award to all eligible employees, and as such, in February 2009, the Compensation Committee and the Board of Directors approved payment of a general award totaling approximately $17.9 million for 2008 in accordance with the Plan, consisting of cash and restricted stock. In as much as the performance goals were not met in 2008, no extraordinary performance award was paid for 2008.

The cash portion of the 2008 award was paid in March 2009 and totaled $7.4 million. Of this amount, $5.4 million was expensed in 2008, $1.7 million was expensed in 2009 and the remainder was billed to partners under joint operating agreements.

In March 2009, the Compensation Committee of the Board of Directors approved a modification to the restricted stock portion of the 2008 award. Due to a decline in the market price of the Company s common stock, the Compensation Committee determined that the number of shares available for issuance under the Compensation Plan was insufficient to cover 100% of the restricted stock portion of the 2008 award. Accordingly, in March 2009, the Company granted to its employees, on a pro-rata basis, substantially all of the shares of restricted stock available to be issued under the Compensation Plan, representing 1,124,603 restricted shares of our common stock with a fair value on the dates of grant of approximately $6.0 million. In May 2009, the Company s shareholders approved an increase in the number of shares available for issuance under the Compensation Plan of 2,000,000 shares. Also in May 2009, the Company granted to its employees 413,513 shares of restricted stock with a fair value on the date of grant of approximately $4.5 million to satisfy the remainder of the 2008 award.

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The compensation expense associated with the restricted stock portion of the 2008 award, less an allowance for estimated forfeitures, is being recognized over the requisite service period of four years beginning on January 1, 2008. Accrued liability amounts of approximately $2.9 million ($2.3 million at December 31, 2008) related to the recognition of compensation expense during the service period prior to the issuance of the restricted shares were reclassified to additional paid-in capital during the year ended December, 2009 (see Note 14).

14. Share-Based Compensation

In accordance with the *Compensation Stock Compensation* Topic of the Codification, we recognize compensation cost for share-based payments to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of grant. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that actually vest.

The Company issues new shares in connection with its share-based payment plans. Restricted shares are subject to forfeiture restrictions and cannot be sold, transferred or disposed of during the restriction period. The holders of restricted shares generally have the same rights as a shareholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares.

A summary of share activity pursuant to our share-based payment plans for the years ended December 31, 2009, 2008 and 2007 is as follows:

	2009		2008		2007	
	Restricted Shares	Weighted Average Grant Date Price Per Share	Restricted Shares	Weighted Average Grant Date Price Per Share	Restricted Shares	Weighted Average Grant Date Price Per Share
Nonvested, beginning of period	233,703	$ 30.33	277,584	$ 29.17	102,860	$ 37.35
Granted	1,570,436	6.91	204,139	32.41	348,675	27.39
Vested	(653,676)	12.18	(221,822)	30.80	(161,004)	30.42
Forfeited	(99,957)	10.77	(26,198)	30.30	(12,947)	30.51
Nonvested, end of period	1,050,506	8.48	233,703	30.33	277,584	29.17

At December 31, 2009, the composition of our nonvested shares outstanding, by year granted, was as follows:

	Restricted Shares
Employees granted in:	
2009	956,711(1)
2008	55,638(2)
Non-employee directors granted in:	
2009	32,320(3)
2008	4,863(4)
2007	974(5)

Total	1,050,506

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Vesting is expected to occur as follows, less any forfeited shares:

(1) Equal installments in December 2010 and 2011.
(2) December 2010.
(3) Equal installments in May 2010, 2011 and 2012.
(4) Equal installments in May 2010 and 2011.
(5) May 2010.

At December 31, 2009, there were 1,860,375 shares of common stock available for award under the Compensation Plan and 618,891 shares of common stock available for award under the Directors Compensation Plan.

The weighted average grant date fair value of shares granted under our share-based payment arrangements during the years ended December 31, 2009, 2008 and 2007 was $10.9 million, $6.6 million and $9.5 million, respectively. The weighted-average fair value of the shares that vested in 2009, 2008 and 2007 was $7.4 million, $3.4 million and $4.8 million, respectively, based on the closing prices on the dates of vesting. Total compensation expense under share-based payment arrangements was $7.7 million ($5.5 million, net of tax), $8.1 million ($5.5 million, net of tax) and $4.8 million ($3.2 million, net of tax) during the years ended December 31, 2009, 2008 and 2007, respectively. As of December 31, 2009, there was $6.3 million of total unrecognized share-based compensation expense related to restricted shares issued. Such amount is expected to be recognized in the period beginning January 2010 and ending April 2012.

15. Employee Benefit Plan

We maintain a defined contribution benefit plan in compliance with Section 401(k) of the Internal Revenue Code (the 401(k) Plan), which covers those employees who meet the 401(k) Plan s eligibility requirements. During 2009, 2008 and 2007, the Company s matching contribution was 100% of each participant s contribution up to a maximum of 5% of the participant s compensation, subject to limitations imposed by the Internal Revenue Service. Our expenses relating to the 401(k) Plan were approximately $1.5 million, $1.4 million and $1.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

16. Earnings (Loss) Per Share

In accordance with the *Earnings Per Share* Topic of the Codification, effective January 1, 2009, the Company adopted certain amendments to the accounting principles relating to its calculation of earnings (loss) per share. The amendments provide that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share under the two-class method. The adoption of these amendments did not have an effect on our basic and diluted loss per common share for the year ended December 31, 2009.

The following table presents the calculation of basic earnings (loss) per common share for the years ended December 31, 2009, 2008 and 2007 (in thousands, except per share amounts):

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$ (187,919)	$ (558,819)	$ 144,300
Less portion allocated to nonvested shares			701

Net income (loss) allocated to common shares	$ (187,919)	$ (558,819)	$ 143,599
Weighted average common shares outstanding	74,852	75,917	75,787
Basic earnings (loss) per common share	$ (2.51)	$ (7.36)	$ 1.89

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Earnings (loss) per share data for the years ended December 31, 2008 and 2007 has been calculated and restated retrospectively for comparability to the 2009 presentation, which did not result in a difference from each of the amounts previously reported as basic and diluted loss per common share for the year ended December 31, 2008 and resulted in a decrease of $0.01 from each of the amounts previously reported as basic and diluted earnings per common share for the year ended December 31, 2007. Diluted earnings (loss) per common share is the same as basic earnings (loss) per common share because the nonvested shares outstanding during the periods are anti-dilutive.

17. Comprehensive Income (Loss)

Our comprehensive income (loss) for the periods indicated is as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$ (187,919)	$ (558,819)	$ 144,300
Amounts reclassified to income, net of income tax of $346 in 2009, $263 in 2008 and $84 in 2007 (1)	643	488	(156)
Change in the fair value of interest rate swaps, net of income tax of $216 in 2007			(402)
Comprehensive income (loss)	$ (187,276)	$ (558,331)	$ 143,742

(1) Includes interest rate swap settlements reclassified to income (2007 only) and amortization of amounts recorded in other comprehensive income upon the de-designation of our interest rate swap as a cash flow hedge. Refer to Note 8.

The balance in accumulated other comprehensive loss at December 31, 2008 was related entirely to our interest rate swap.

18. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2009	2008	2007
Cash paid for interest, net of interest capitalized of $6,662 in 2009 $19,292 in 2008 and $25,100 in 2007	$ 37,286	$ 31,231	$ 31,573
Cash paid for income taxes	100	26,591	34,030

During the year ended December 31, 2009, we received refunds of federal income taxes paid in prior years totaling $22.3 million.

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19. Selected Quarterly Financial Data UNAUDITED

Unaudited quarterly financial data for the years ended December 31, 2009 and 2008 are as follows (in thousands, except per share amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2009				
Revenues	$ 117,422	$ 150,432	$ 167,042	$ 176,100
Operating income (loss) (1)	(258,347)	(3,769)	7,322	34,935
Net income (loss) (1)	(244,577)	(5,974)	(1,322)	63,954
Basic and diluted earnings (loss) per common share (1)(3)(4)	(3.22)	(0.08)	(0.02)	0.84
Year Ended December 31, 2008				
Revenues	$ 356,495	$ 461,015	$ 289,793	$ 108,306
Operating income (loss) (2)	127,485	210,097	121,828	(1,266,555)
Net income (loss) (2)	79,806	134,610	78,181	(851,416)
Basic and diluted earnings (loss) per common share (2)(3)(4)	1.05	1.76	1.02	(11.21)

(1) The carrying amount of our oil and natural gas properties has been written down by $218.9 million as of March 31, 2009 through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of lower natural gas prices at March 31, 2009, as compared to December 31, 2008. This amount includes an increase of $13.9 million from the previously reported amount of $205.0 million as a result of further analysis of our March 31, 2009 ceiling test impairment calculation. As such, operating income, net income and our basic and diluted loss per common share for the first quarter of 2009 have been adjusted as well.

(2) In December 2008, the carrying amount of our oil and natural gas properties was written down by $1.2 billion through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008.

(3) In accordance with the *Earnings Per Share* Topic of the Codification, effective January 1, 2009, the Company adopted certain amendments to the accounting principles relating to its calculation of earnings (loss) per share. The adoption of these amendments to the Codification did not have an effect on our basic and diluted earnings (loss) per common share for any of the quarterly periods in 2009 except for the fourth quarter, which resulted in decreases to our basic and diluted earnings per share of $0.02 and $0.01, respectively. Quarterly earnings (loss) per share data for 2008 has been calculated and restated retrospectively for comparability to the 2009 presentation, which resulted in a decrease of $0.01 from each of the amounts previously reported as basic and diluted earnings per common share for the second and third quarters of 2008. Refer to Note 16 for additional information about these amendments to the Codification.

(4) The sum of the individual quarterly earnings (loss) per share may not agree with year-to-date earnings (loss) per share because each quarterly calculation is based on the income (loss) for that quarter and the weighted average number of shares outstanding during that quarter.

20. Supplemental Oil and Gas Disclosures UNAUDITED

Geographic Area of Operation

All of our proved reserves are located within the same geographic area (defined as a country), with substantially all of those reserves located in the Gulf of Mexico. Therefore the following disclosures about our costs incurred, results of operations and proved reserves are on a total-company basis.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Capitalized Costs

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

	December 31, 2009	2008	2007
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 4,637.2	$ 4,580.1	$ 3,297.0
Unproved oil and natural gas properties and equipment	95.5	104.6	508.2
Accumulated depreciation, depletion and amortization	(3,743.3)	(3,210.4)	(1,547.4)
	$ 989.4	$ 1,474.3	$ 2,257.8

Costs Not Subject To Amortization

Costs not subject to amortization relate to unproved properties which are excluded from amortizable capital costs until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. Subject to industry conditions, evaluation of most of these properties is expected to be completed within one to five years. The following table provides a summary of costs that are not being amortized as of December 31, 2009, by the year in which the costs were incurred (in millions):

	Total	2009	2008	2007	Prior to 2007
Costs excluded by year incurred:					
Acquisition costs	$ 58.4	$	$	$	$ 58.4
Capitalized interest	18.9	5.5	5.8	5.5	2.1
	$ 77.3	$ 5.5	$ 5.8	$ 5.5	$ 60.5

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

The following costs were incurred in oil and gas acquisition, exploration, and development activities during the years ended December 31, 2009, 2008, and 2007 (in millions):

	Year Ended December 31, 2009	2008	2007
Costs incurred (1):			
Proved property acquisitions	$ 17.5	$ 139.0	$ 3.6
Development	142.9	373.4	328.3
Exploration (2)	97.5	352.5	170.2
Unproved property acquisitions (3)	12.2	21.1	21.0

$ 270.1	$ 886.0	$ 523.1

(1) Includes additions (reductions) to our asset retirement obligations of ($6.0) million, $111.1 million and $161.9 million during the years ended December 31, 2009, 2008 and 2007, respectively, associated with acquisitions, liabilities incurred and revisions of estimates. Refer to Note 2.
(2) Includes seismic costs of approximately $6.6 million, $14.5 million and $40.4 million incurred during the years ended December 31, 2009, 2008 and 2007, respectively.
(3) The amounts for 2009, 2008 and 2007 include capitalized interest associated with properties classified as unproved at December 31, 2009, 2008 and 2007, respectively.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Depreciation, depletion, amortization and accretion expense

The following table presents our DD&A expense per Mcfe of products sold.

	Year Ended December 31,		
	2009	**2008**	**2007**
Depreciation, depletion, amortization and accretion per Mcfe	$ 3.61	$ 5.33	$ 4.21

As discussed below, DD&A expense for 2009 increased by approximately $7.6 million ($0.08 per Mcfe) as a result of our adoption of certain amendments to the *Extractive Activities Oil and Gas* Topic of the Codification.

Oil and Natural Gas Reserve Information

Our net proved oil and natural gas reserves at December 31, 2009, 2008 and 2007 have been estimated by our independent petroleum consultant in accordance with definitions and guidelines established by the SEC and the FASB. In January 2010, the FASB issued certain amendments to the *Extractive Activities Oil and Gas* Topic of the Codification that updated and aligned the FASB s reserve estimation and disclosure requirements for oil and natural gas companies with the reserve estimation and disclosure requirements that were adopted by the SEC in December 2008. The FASB s amendments and the SEC s new requirements became effective for annual reporting periods ending on or after December 31, 2009. Collectively, the new rules permit the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of *proved reserves* which was changed to indicate, among other things, that commencing with year-end 2009 entities must use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than end-of-period commodity prices, when estimating quantities of proved reserves. Similarly, the prices used to calculate the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future cash flows have been changed from end-of-period commodity prices to the 12-month average commodity prices used in calculating proved reserves. Beginning in the fourth quarter of 2009, the estimated future net revenues used to calculate the ceiling test are based on the 12-month average commodity price for each product. Also, because it is our policy to use end-of-period reserves in the determination of quarterly depletion, our DD&A expense for the fourth quarter of 2009 was calculated using proved reserves at December 31, 2009 that were determined in accordance with the new rules. Additionally, entities must separately disclose information about reserve quantities and certain financial statement amounts for geographic areas that represent 15 percent or more of proved reserves, and equity-method investees should be included in determining whether an entity has significant oil and gas producing activities. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, 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.

The initial application of these rules resulted in the removal of 23.2 Bcfe of proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded, as required. In addition, positive revisions of 27.5 Bcfe that would have resulted from using end-of-period commodity prices as of December 31, 2009 ($76.00 per barrel for oil and natural gas liquids and $5.79 per MMBtu for natural gas) were offset by 25.1 Bcfe, the impact of which is attributable to the new requirement that oil and natural gas reserves are to be measured using the 12-month average commodity price for each product ($57.65 per barrel for oil and natural gas liquids and $3.87 per MMBtu for natural gas). The impact on our DD&A expense for 2009 related to the adoption of these amendments to the Codification was an approximate $7.6 million ($0.08 per Mcfe) increase in DD&A.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represent estimates only and are inherently imprecise and may be subject to substantial revisions as additional information such as reservoir performance, additional drilling, technological advancements and other factors become available. Decreases in the prices of oil and natural gas could have an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow. We are not the operator with respect to approximately 26% of our proved developed non-producing reserves, so we may not be in a position to control the timing of all development activities.

The following sets forth estimated quantities of our net proved, proved developed and proved undeveloped oil (including natural gas liquids) and natural gas reserves, virtually all of which are located offshore in the Gulf of Mexico. These reserve estimates exclude insignificant royalties and interests owned by the Company due to the unavailability of such information.

	Oil (MBbls) (1)	Natural Gas (MMcf) (1)	Total Oil and Natural Gas (MMcfe) (1)(2)
Proved reserves as of December 31, 2006	55,659	401,237	735,189
Revisions of previous estimates (3)	579	(22,176)	(18,702)
Extensions and discoveries (4)	2,910	30,979	48,441
Purchase of minerals in place	224	76	1,419
Sales of reserves	(74)	(570)	(1,015)
Production	(8,301)	(76,727)	(126,533)
Proved reserves as of December 31, 2007	50,997	332,819	638,799
Revisions of previous estimates (3)	(12,199)	(84,349)	(157,546)
Extensions and discoveries (5)	3,700	25,035	47,236
Purchase of minerals in place (6)	8,348	10,439	60,528
Production	(6,970)	(56,072)	(97,892)
Proved reserves as of December 31, 2008	43,876	227,872	491,125
Revisions of previous estimates (7)	(2,074)	(13,042)	(25,484)
Extensions and discoveries (8)	1,481	14,511	23,402
Purchase of minerals in place	43	434	692
Sales of reserves (9)	(1,927)	(12,397)	(23,957)
Production	(7,197)	(51,621)	(94,806)
Proved reserves as of December 31, 2009	34,202	165,757	370,972
Year-end proved developed reserves:			
2009	23,709	141,275	283,527
2008	24,640	186,302	334,143
2007	26,666	235,293	395,291
Year-end proved undeveloped reserves:			
2009	10,493	24,482	87,445
2008	19,235	41,570	156,981
2007	24,330	97,526	243,508

(1) Estimated reserves as of December 31, 2006, 2007 and 2008 are based on end-of-period commodity prices in accordance with the previous definitions and guidelines of the SEC and the FASB in effect on those respective dates. Estimated reserves as of December 31, 2009 are based on the unweighted average of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

first-day-of-the-month commodity prices over the period January 2009 through December 2009 in accordance with current definitions and guidelines set forth by the SEC and the FASB.

(2) One million cubic feet equivalent (MMcfe) is determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding).

(3) Revisions of previous estimates can result from changes in commodity prices, changes in the performance of our properties and changes in the regulations which govern the estimation and reporting of reserves applicable to oil and natural gas companies. Damage to our facilities from tropical storms and hurricanes can also cause negative revisions. For 2007, positive revisions due to price changes were 19.8 Bcfe and negative revisions due to performance were 38.5 Bcfe. For 2008, negative revisions due to pricing, performance and hurricane damage were 105.0 Bcfe, 42.4 Bcfe and 10.1 Bcfe, respectively.

(4) Approximately 68% of these volumes are attributable to extensions and discoveries resulting from five of our six successful exploratory wells in 2007 and the deepening of the previously drilled No. 3 well at Green Canyon 82 Healey. Approximately 37% of the oil and natural gas equivalent volumes of such extensions and discoveries were attributable to four new exploratory wells on the conventional shelf, 4% of such volumes were attributable to one new exploratory well on the deep shelf and 27% of such volumes were attributable to the deepening of the Green Canyon 82 No. 3 well.

(5) Substantially all of these volumes are attributable to extensions and discoveries resulting from our participation in the drilling of 18 successful exploratory wells in 2008, of which 16 were on the conventional shelf and two were on the deep shelf.

(6) The amount for 2008 relates to volumes attributable to the purchase of the remaining working interest in Ship Shoal 349 field from Apache. For additional details about this transaction, refer to Note 4.

(7) Revisions for 2009 included decreases attributable to the new reserve reporting requirements for oil and natural gas companies enacted by the SEC and the FASB, which became effective for annual reporting periods ending on or after December 31, 2009. The initial application of these rules resulted in the removal of 23.2 Bcfe of proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded, as required. In addition, positive revisions of 27.5 Bcfe that would have resulted from using end-of-period commodity prices as of December 31, 2009 ($76.00 per barrel for oil and natural gas liquids and $5.79 per MMBtu for natural gas) were offset by 25.1 Bcfe, the impact of which is attributable to the new requirement that oil and natural gas reserves are to be measured using the 12-month average commodity price for each product ($57.65 per barrel for oil and natural gas liquids and $3.87 per MMBtu for natural gas). Also included in the revisions of previous estimates for 2009 are negative revisions of 4.7 Bcfe due to performance.

(8) The majority of these volumes are attributable to extensions and discoveries resulting from our participation in the drilling of eight successful exploratory wells in 2009, all of which were on the conventional shelf.

(9) In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. For additional details about these transactions, refer to Note 4.

Standardized Measure of Discounted Future Net Cash Flows

The following presents the standardized measure of discounted future net cash flows related to our proved oil and natural gas reserves together with changes therein, as defined by the FASB. Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the unweighted average of first-day-of-the-month commodity prices for the year ended December 31, 2009 and period-end commodity prices for the years ended December 31, 2008 and 2007. The unweighted average of first-day-of-the-month commodity prices over the period January 2009 through December 2009 adjusted by lease for quality, transportation fees, energy content and regional price differentials related to proved reserves of natural gas approximated $3.80 per Mcf and for oil and natural gas liquids approximated $53.91 per barrel at December 31, 2009. At December 31, 2008 and 2007, the end-of-period prices adjusted by lease for quality, transportation fees,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

energy content and regional price differentials related to proved reserves of natural gas approximated $6.17 and $6.88 per Mcf, respectively, and for oil and natural gas liquids approximated $37.71 and $87.22 per barrel, respectively. Future production and development costs are based on costs in effect at the end of each of the respective years with no escalations. Estimated future net cash flows, net of future income taxes, have been discounted to their present values based on a 10% annual discount rate.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of our oil and natural gas reserves. These estimates reflect proved reserves only and ignore, among other things, future changes in prices and costs, revenues that could result from probable reserves which could become proved reserves in 2010 or later years and the risks inherent in reserve estimates. The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 2,474,260	$ 3,059,353	$ 6,737,806
Future costs:			
Production	(604,794)	(667,132)	(920,193)
Development	(212,835)	(396,103)	(875,323)
Dismantlement and abandonment	(496,540)	(751,324)	(701,991)
Income taxes	(186,101)	(136,471)	(1,212,887)
Future net cash inflows before 10% discount	973,990	1,108,323	3,027,412
10% annual discount factor	(313,594)	(346,641)	(915,137)
	$ 660,396	$ 761,682	$ 2,112,275

	Year Ended December 31,		
	2009	2008	2007
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 761,682	$ 2,112,275	$ 1,691,873
Sales and transfers of oil and gas produced, net of production costs	(386,331)	(960,918)	(857,422)
Net changes in price, net of future production costs	(34,841)	(1,572,781)	1,371,346
Extensions and discoveries, net of future production and development costs	98,087	259,952	304,519
Changes in estimated future development costs	144,590	156,720	(401,536)
Previously estimated development costs incurred	224,802	275,344	207,111
Revisions of quantity estimates	(86,600)	(486,811)	(118,774)
Accretion of discount	78,789	272,483	205,484
Net change in income taxes	(32,394)	752,463	(297,548)
Purchases of reserves in-place	(9,927)	135,761	12,602
Sales of reserves in-place	(205,691)		(6,195)
Changes in production rates due to timing and other	108,230	(182,806)	815
Net increase (decrease) in standardized measure	(101,286)	(1,350,593)	420,402
Standardized measure, end of year	$ 660,396	$ 761,682	$ 2,112,275

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Item 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure***
None.

Item 9A. ***Controls and Procedures***
Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by the SEC and that any material information relating to us is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by Exchange Act Rule 13a-15(b), we performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have each concluded that as of December 31, 2009 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms, and that our controls and procedures are designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management s Annual Report on Internal Control Over Financial Reporting

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2009, is set forth in *Management s Report on Internal Control over Financial Reporting* included in Item 8 of this Annual Report on Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2009, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***
None.

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PART III

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

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K and to the information set forth in Item 4A of this report.

Item 11. ***Executive Compensation***

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

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

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

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

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

Item 14. ***Principal Accountant Fees and Services***

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

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

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

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

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

2. Exhibits:

Exhibit Number	**Description**
2.1	Agreement and Plan of Merger among Kerr-McGee Oil & Gas Corporation, Kerr-McGee Oil & Gas (Shelf) LLC, W&T Offshore, Inc., and W&T Energy V, LLC, effective October 1, 2005. (Incorporated by reference to Exhibit 99.1 of the Company s Current Report on Form 8-K, filed January 27, 2006)
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K, filed February 24, 2006)
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company s Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
4.1	Specimen Common Stock Certificate. (Incorporated by reference to Exhibit 4.1 of the Company s Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))

4.2	Indenture, dated as of June 13, 2007, between W&T Offshore, Inc., Wells Fargo Bank, National Association, as trustee, and the Guarantors, as defined therein. (Incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K, filed June 15, 2007)
10.1	Form of Indemnification and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors. (Incorporated by reference to Exhibit 10.8 of the Company s Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.2*	Employment Agreement dated April 21, 2004, by and between Tracy W. Krohn and W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.9 of the Company s Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.3*	Employment Agreement dated October 20, 2005, by and between Reid Lea and the Company. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed October 26, 2005)
10.4*	Indemnification and Hold Harmless Agreement dated March 25, 2005, by and between Virginia Boulet and the Company. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed March 25, 2005)
10.5*	Indemnification and Hold Harmless Agreement dated January 20, 2006, by and between S. James Nelson, Jr. and the Company. (Incorporated by reference to Exhibit 10.10 of the Company s Annual Report on Form 10-K, filed March 31, 2006)
10.6*	2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.11 of the Company s Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.7*	W&T Offshore, Inc. Long-Term Incentive Compensation Plan (2003). (Incorporated by reference to Exhibit 10.13 of the Company s Registration Statement on Form S-1/A, filed January 12, 2005 (File No. 333-115103))
10.8*	W&T Offshore, Inc. Long-Term Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.10 of the Company s Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.9*	W&T Offshore, Inc. 2005 Annual Incentive Plan. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed October 27, 2005)
10.10	Exchange Agreement dated November 25, 2002, by and among W&T Offshore, Inc., and ING Furman Selz Investors III L.P., ING Barings U.S. Leveraged Equity Plan LLC, ING Barings Global Leveraged Equity Plan Ltd. and Jefferies & Company, Inc. (Incorporated by reference to Exhibit 10.12 of the Company s Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.11	Third Amended and Restated Credit Agreement, dated May 26, 2006 by and between W&T Offshore, Inc. and Toronto Dominion (Texas) LLC, Lehman Commercial Paper Inc., Harris Nesbitt Financing, Inc., Fortis Capital Corp., Bank of Scotland, Natexis Banques Populaires and various financial institutions parties thereto. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed August 7, 2006)
10.12	First Amendment to Third Amended and Restated Credit Agreement, dated June 9, 2006. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed August 7, 2006)
10.13	Second Amendment to Third Amended and Restated Credit Agreement, dated July 27, 2006. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed August 7, 2006)

10.14*	Employment Agreement dated July 11, 2006, by and between the W&T Offshore, Inc. and Stephen L. Schroeder. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed July 12, 2006)
10.15*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Stephen L. Schroeder, dated July 5, 2006. (Incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K, filed July 12, 2006)
10.16*	First Amendment to Employment Agreement by and between W&T Offshore, Inc. and Reid Lea effective September 28, 2005. (Incorporated by reference to Exhibit 10.3 of the Company s Current Report on Form 8-K, filed July 12, 2006)
10.17*	Employment Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed February 26, 2007)
10.18*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007. (Incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K, filed February 26, 2007)
10.19	Purchase Agreement, dated June 8, 2007, by and among W&T Offshore, Inc., Morgan Stanley & Co. Incorporated (as Representative of the Initial Purchasers) and the Guarantors listed on Schedule IV attached thereto. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed June 15, 2007)
10.20	Third Amendment to Third Amended and Restated Credit Agreement, as amended, dated June 7, 2007. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed July 19, 2007)
10.21	Waiver and Fourth Amendment to Third Amended and Restated Credit Agreement, as amended, dated November 6, 2007. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed November 7, 2007)
10.22*	Indemnification and Hold Harmless Agreement dated May 5, 2008, by and between Samir G. Gibara and the Company. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed May 14, 2008)
10.23	Fifth Amendment to Third Amended and Restated Credit Agreement, as amended, dated July 24, 2008. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed July 29, 2008)
10.24*	Employment Agreement, dated effective September 28, 2005, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed September 26, 2008)
10.25*	First Amendment to Employment Agreement, dated July 18, 2006, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K, filed September 26, 2008)
10.26*	Second Amendment to Employment Agreement, dated September 24, 2008, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.3 of the Company s Current Report on Form 8-K, filed September 26, 2008)
10.27*	Indemnification and Hold Harmless Agreement, dated September 24, 2008, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.4 of the Company s Current Report on Form 8-K, filed September 26, 2008)
10.28*	First Amendment to Employment Agreement, dated October 14, 2008, by and between W&T Offshore, Inc. and Tracy W. Krohn. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed October 20, 2008)

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10.29*	Sixth Amendment to Third Amended and Restated Credit Agreement, as amended, dated December 18, 2008. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed December 23, 2008)
10.30*	Seventh Amendment to Third Amended and Restated Credit Agreement, dated May 4, 2009. (Incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
10.31*	Second Amendment to W&T Offshore, Inc. Long-Term Incentive Compensation Plan. (Incorporated by reference from Appendix B to the Company s Definitive Proxy Statement on Schedule 14A filed April 17, 2009)
10.32*	Third Amendment to W&T Offshore, Inc. Long-Term Incentive Compensation Plan. (Incorporated by reference from Appendix A to the Company s Definitive Proxy Statement on Schedule 14A filed April 17, 2009)
10.33*	Indemnification and Hold Harmless Agreement, dated August 5, 2009, by and between B. Frank Stanley and the Company. (Incorporated by reference to Exhibit 10.8 of the Company s Registration Statement on Form S-1, filed May 1, 2004 (File No. 333-115103)).
14.1	W&T Offshore, Inc. Code of Business Conduct and Ethics (as amended). (Incorporated by reference to Exhibit 14.1 of the Company s Current Report on Form 8-K, filed November 17, 2005)
21.1**	Subsidiaries of the Registrant.
23.1**	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
23.2**	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
31.1**	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2**	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer of W&T Offshore, Inc. pursuant to 18 U.S.C. § 1350.
99.1**	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.

* Management Contract or Compensatory Plan or Arrangement.
** Filed or furnished herewith.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

Bcf. Billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe. Barrel of oil equivalent.

Conventional shelf well. A well drilled in water depths less than 500 feet.

Deep shelf well. A well drilled on the outer continental shelf to subsurface depths greater than 15,000 feet.

Deepwater. Water depths below 500 feet in the Gulf of Mexico.

Deterministic estimate. Refers to a method of estimation whereby a single value for each parameter in the reserves calculation is used in the reserves estimation procedure.

Developed reserves. Oil and natural gas reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development project. A project by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. Refers to a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Exploitation. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

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Extension well. A well drilled to extend the limits of a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of oil equivalent. *Mcf*. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or other hydrocarbon.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil condensate or natural gas liquids.

MMS. The Minerals Management Service, a bureau in the U.S. Department of the Interior, is the federal agency that manages the nation s natural gas, oil and other mineral resources on the outer continental shelf (OCS).

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

Oil. Crude oil, condensate and natural gas liquids.

OCS block. A unit of defined area for purposes of management of offshore petroleum exploration and production by the MMS.

Probabilistic estimate. Refers to a method of estimation whereby the full range of values that could reasonably occur for each unknown parameter in the reserves estimation procedure is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Productive well. A well that is found to have economically producible hydrocarbons.

Proved properties. Properties with proved reserves.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in this definition, existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be

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the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(22) of Regulation S-X.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

PV-10 value. The present value of estimated future net revenues to be generated from the production of proved reserves as determined in accordance with the rules and regulations of the SEC, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%.

Reasonable certainty. When deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities of hydrocarbons will be recovered. When probabilistic methods are used, reasonable certainty means at least a 90% probability that the quantities of hydrocarbons actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience, engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

Recompletion. The completion for production of an existing well bore in another formation from that which the well has been previously completed.

Reliable technology. A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Estimated remaining quantities of oil, natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering the oil, natural gas or related substances to market, and all permits and financing required to implement the project.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Undeveloped reserves. Oil and natural gas reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties. Properties with no proved reserves.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 1, 2010.

W&T OFFSHORE, INC.

By: /s/ JOHN D. GIBBONS
John D. Gibbons
Senior Vice President, Chief Financial Officer and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 1, 2010.

/s/ TRACY W. KROHN **Tracy W. Krohn**	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ JOHN D. GIBBONS **John D. Gibbons**	Senior Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer)
/s/ VIRGINIA BOULET **Virginia Boulet**	Director
/s/ J.F. FREEL **J.F. Freel**	Secretary and Director
/s/ SAMIR G. GIBARA **Samir G. Gibara**	Director
/s/ ROBERT I. ISRAEL **Robert I. Israel**	Director
/s/ S. JAMES NELSON, JR. **S. James Nelson, Jr.**	Director
/s/ B. FRANK STANLEY **B. Frank Stanley**	Director