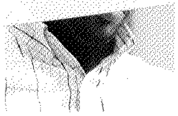
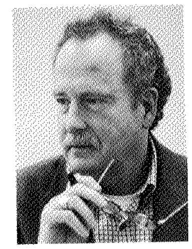
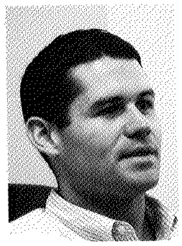


W&T OFFSHORE

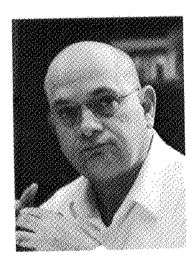
2012 ANNUAL REPORT





GROW&TH

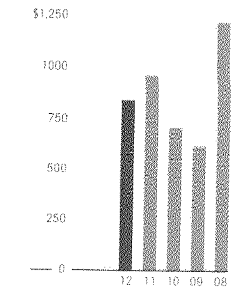
"How does a company continue to grow amidst economic turmoil and political uncertainty?"
The people of W&T tell you how.



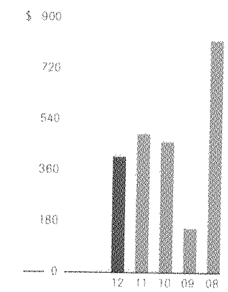
SUMMARY OF SELECTED FINANCIAL DATA

Year Ending December 31	2012	2011	2010	2009	2008
Income Statement					
Total Revenues	$ 874,491	$ 971,047	$ 705,783	$ 610,996	$ 1,215,609
Operating Income (Loss)	$ 169,310	$ 329,460	$ 166,789	$ (219,859)	$ (807,145)
Net Income (Loss)	$ 71,984	$ 172,817	$ 117,892	$ (187,919)	$ (558,819)
Cash-Flow Statement					
Operating Activities	$ 385,137	$ 521,478	$ 464,772	$ 156,266	$ 882,496
Capex (oil and natural gas properties)	$ 684,863	$ 719,026	$ 415,653	$ 276,134	$ 774,879
Balance Sheet					
Total Assets	$ 2,348,987	$ 1,868,925	$ 1,424,094	$ 1,326,833	$ 2,056,186
Long-Term Debt	$ 1,087,611	$ 717,000	$ 450,000	$ 450,000	$ 653,172
Shareholders' Equity	$ 541,187	$ 544,574	$ 421,743	$ 358,950	$ 572,227
Operating Data					
Net Sales:					
Oil (MMBbls)	6.0	6.1	5.9	6.1	5.9
NGLs (MMBbls)	2.1	1.9	1.2	1.1	1.1
Natural Gas (Bcf)	53.8	53.7	44.7	51.6	56.1
Total Oil Equivalent (MMboe)	17.1	16.9	14.5	15.8	16.3
Total Natural Gas Equivalent (Bcfe)	102.8	101.5	87.0	94.8	97.9
Average Daily Oil Sales (Mboe/d)	46.8	46.4	39.7	43.3	44.6
Average Daily Gas Sales (MMcfe/d)	280.9	278.2	238.4	259.7	267.5
Average Realized Sales Price:					
Oil ($/Bbl)	$ 104.35	$ 105.92	$ 77.33	$ 59.96	$ 105.74
NGLs ($/Bbl)	$ 39.75	$ 55.81	$ 43.65	$ 31.96	$ 60.62
Natural Gas ($/Mcf)	$ 2.94	$ 4.12	$ 4.55	$ 3.97	$ 9.40
Oil Equivalent ($/Boe)	$ 50.93	$ 57.32	$ 48.87	$ 38.32	$ 74.50
Natural Gas Equivalent ($/Mcfe)	$ 8.49	$ 9.55	$ 8.15	$ 6.39	$ 12.42
Estimated Net Proved Reserves					
Oil (MMBbls)	54.8	51.4	34.0	31.2	40.0
NGLs (MMBbls)	15.2	17.1	4.2	3.0	3.9
Natural Gas (Bcf)	285.1	289.7	256.3	165.8	227.9
Total Oil Equivalent (MMBoe)	117.5	116.9	80.9	61.8	81.9
Total Natural Gas Equivalent (Bcfe)	705.1	701.1	485.4	371.0	491.1
Total Proved Developed (MMBoe)	86.9	76.4	65.2	47.3	55.7
Total Proved Developed (Bcfe)	521.2	458.2	391.3	283.5	334.1
Proved Undeveloped (MMBoe)	30.7	40.5	15.7	14.5	26.2
Proved Undeveloped (Bcfe)	183.9	242.9	94.1	87.5	157.0
Proved Developed Reserves as a % of Proved Reserves	73.9%	65.4%	80.6%	76.4%	68.0%

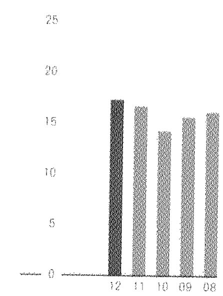
Forward-Looking Statements This Annual Report (including the letter from Tracy W. Krohn, our Chief Executive Officer) contains forward-looking statements within the meaning of the Private Litigation Securities Reform Act of 1995 that involve risks, uncertainties and assumptions. If the risks or uncertainties 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 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 "Risk Factors" in Item 1A and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of the Form 10-K included as part of and attached to this Annual Report and may be discussed from time to time in our reports filed with the Securities and Exchange Commission subsequent to this report. We assume no obligation, nor do we intend to update these forward-looking statements.



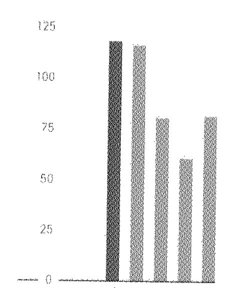
Revenues
(In millions)



Cash Provided by Operating Activies
(In millions)



Production
(MMBoe)



Proved Reserves
(MMBoe)

"With over 1.4 million gross acres under lease, the majority of which is held by production, we have the flexibility within our project portfolio to move between projects to seek the best compliment of production and reserve growth."

Debra Fanning, *Lease Records Supervisor*

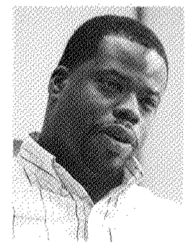
"The Company continues to pursue a 'balanced approach', meaning the balance of offshore projects, which are more often characterized by high production and high IRRs, with onshore projects, that have long life reserves but lower IRRs. In other words the offshore generates a large amount of cash flow with its high production rate wells; while the onshore provides reserves with a predictable multiple year development program." **Jamie Vazquez,** *President*

EXPLORAT

"While utilizing the latest techniques in seismic reprocessing and analysis to identify viable exploration projects, we have added new Geologists, Geophysicists, and Petrophysicists to expand our exploration team. The benefits of our increased efforts in applying industry leading technology is exemplified by the 93% success rate on our exploration wells in 2012. A good example of our success is the continued expansion of the resource potential of our Ship Shoal 349 "Mahogany" field." **Jim Hersch**, *Exploration Manager*

The people of W&T tell you how.

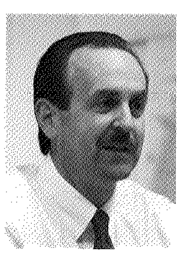
"Over the last few years we have increased our focus on exploration and believe that we have significantly enhanced our ability to grow the Company through a successful exploration program, incorporating onshore and offshore drilling. In 2013, we are increasing our focus on exploration and we expect to replace and increase reserves with the drill bit."
William Williford, *Exploration Project Manager*

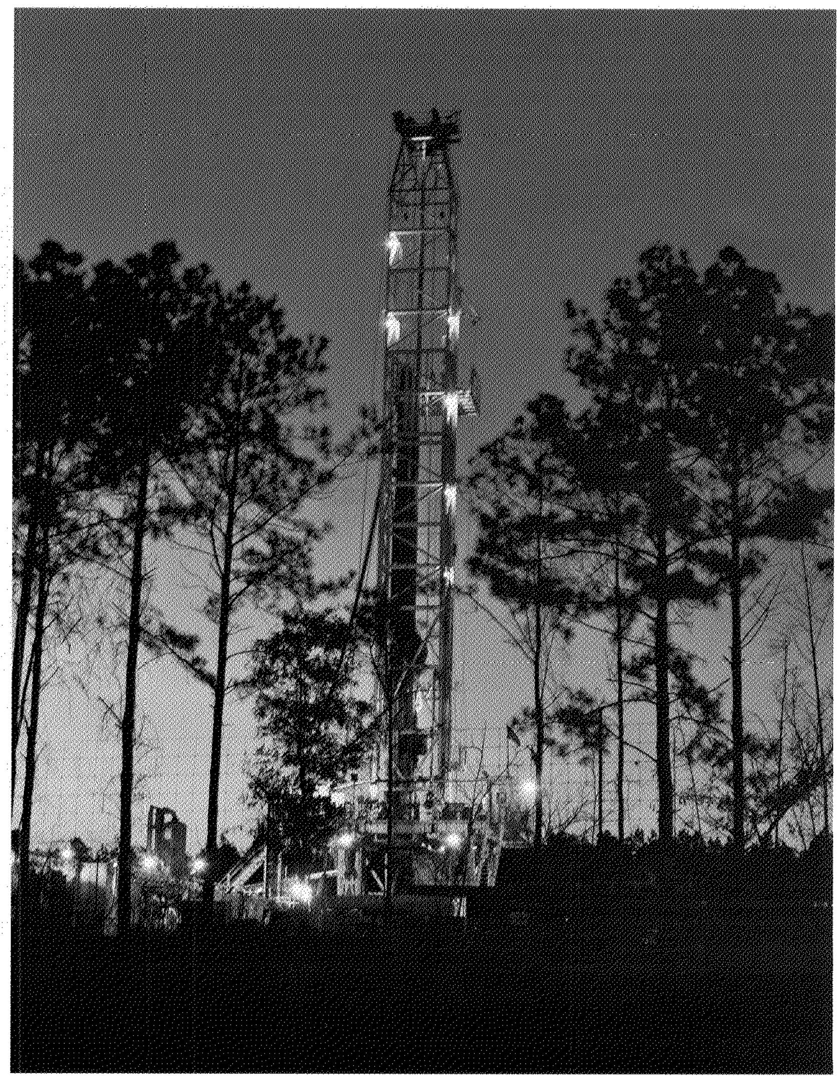


"In recent years we have expanded our operating presence and focus into the Deepwater of the Gulf of Mexico. This is exemplified with the fairly recent acquisition of 65 deepwater blocks, six of which are producing and 59 are undeveloped blocks with exploration upside. The gross potential of targets being evaluated provides the company with numerous opportunities to generate significant value." **Scott Challburg,** *Senior Landman*

ION

"In 2012 we demonstrated that our increased focus on growing the Company organically is becoming a reality. We added substantial reserves in West Texas from exploration and development drilling and initiated a robust exploration program both onshore and offshore that we expect to have a positive impact on our proved reserve volumes in 2013."
Tom Murphy,
Senior Vice President and Chief Operations Officer

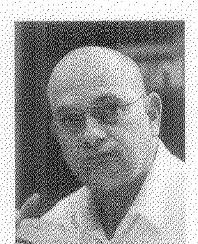




"As we have grown our presence onshore over the past two years, we continue to enhance our operating methods and techniques to explore and develop our acreage. Looking back at 2012, there's no better proof of success than to see new wells outperforming our earlier efforts. That's a trend that we expect will continue as we move forward." **Cliff Williams,** *Vice President and General Manager Offshore*

DEVEL

"The addition of our Yellow Rose field in 2011 brought a new dimension and tremendous growth to our Company. There are numerous growth opportunities associated with down-spacing vertical wells, drilling horizontal wells to known producing horizons and testing new potentially productive horizons which provides a multi-year inventory." **Paul Baker,** *Vice President and General Manager Onshore*



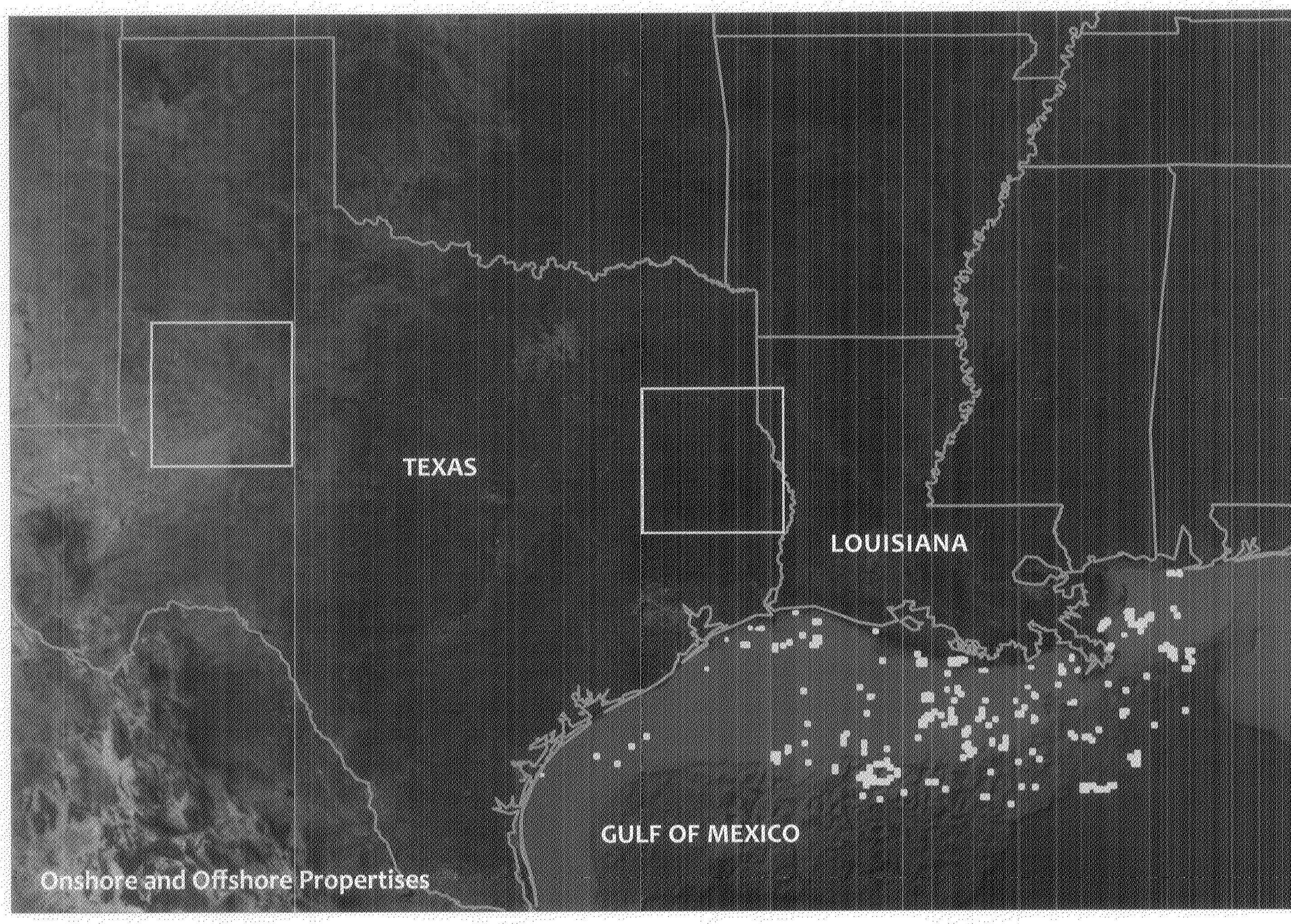
"Through our development efforts in 2012, we increased the value of reserves by converting 50% of our 2011 proved undeveloped reserves to a proved developed status and increased our proved developed crude oil reserves by 51%. This allows us to continue to take advantage of the on-going strength in oil prices and the premium we receive for our Gulf Coast oil production."
Joe Serio, *Offshore Western Asset Manager*

The people of W&T tell you how.

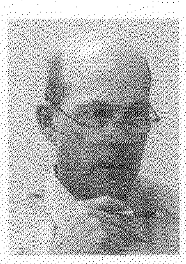
"W&T has a history of fully evaluating the potential of our fields and realizing substantial value which is accomplished with an experienced staff, expertise and hard work."

Selwyn Wilkinson, *Senior Geosciences Technician*

OPMENT



ACQU



"Historically, W&T has been a company that grew primarily through acquisitions and complemented those efforts with highly successful drilling results. We have significant experience and expertise in executing accretive acquisitions and we will continue to use acquisitions to supplement our growth and take advantage of our substantial liquidity position". **Danny Gibbons,** *Senior Vice President and Chief Financial Officer*

The people of W&T tell you how.

"We maintain a disciplined approach to acquisitions requiring that the property generates cash flow, is financeable and has identified upside. Using this criteria, we have been very successful over nearly three decades."
Steve Schroeder, *Senior Vice President and Chief Technical Officer*

"In 2013, we will continue to seek accretive acquisitions to supplement our expected organic growth." **Janet Yang,** *Director of Strategic Planning and Analysis*

ISITIONS

"At W&T, we do not limit ourselves to specific basins and instead keep an open mind and view each potential transaction in the light of its own value looking at full cycle economics and the long term benefits for the Company."
Terry Groh, *Manager, Acquisitions and Divestitures*

LETTER TO SHAREHOLDERS:

We had another solid year in 2012 as we focused on expanding our opportunity set, growing our assets, and creating long-term shareholder value. We grew our production, increased our reserves, and expanded our operations, while maintaining good liquidity and cash flow. Our successful development program allowed us to convert 50% of our undeveloped reserves to the proved developed category and hence cash flow. We grew our proved developed crude oil reserves by 51% over the 2011 volumes.

Over the past few years, we have increased our emphasis on exploration and we expect to grow the Company organically. We have been expanding our team of exploration geoscientists, acquiring undeveloped leasehold acreage and expanding our seismic database to increase our exploration prospect inventory both onshore and offshore. In the latter part of 2012, we began to see a significant impact of our new focus with a successful discovery in the Gulf of Mexico deepwater at our Big Bend joint venture and onshore in our Yellow Rose horizontal drilling program. Additionally, our more recent results in our East Texas Star prospect have been encouraging. These combined efforts are expected to be a part of the make up of an increase in reserves and production in 2013.

In 2013, we will continue to pursue exploration offshore on both the conventional shelf and deepwater of the Gulf of Mexico and onshore Texas. Our capital expenditure budget of $450 million is currently allocated 63% to exploration and 37% to development projects. Deepwater exploration is a strong focus for W&T this year as we have a large number of undeveloped deepwater blocks along with a growing inventory of seismic data and projects that are moving toward a "drill-ready" status. As part of this effort, we expect to increase our presence in the deepwater with new wells and exploration joint ventures.

In West Texas, we believe that there is substantial upside associated with drilling additional horizontal wells in the Wolfcamp formation and testing newly identified zones, as well as continued vertical down spacing. Approximately 80% of our Yellow Rose lease acreage is held by production, which will allow us to prudently take advantage of the best opportunities in the field. In East Texas, we will drill at least one if not more exploration wells at our Star Prospect.

The onshore expansion that has been underway over the last couple of years is yielding sufficient opportunities and positioning us to pursue a more balanced approach to our growth. We believe that a balanced approach enhances our ability to maintain good liquidity and high cash flow. Further, it helps us manage our finding and developments costs, and allows us to plan for multiple years and facilitate our goal of generating a more predictable year-over-year growth rate.

TEA

In 2013, we will also continue to pursue the acquisition of assets that have upside and that would be accretive to the Company. As is our history, we don't budget for acquisitions but we maintain the liquidity and flexibility to complete a strategic deal once identified. We have good strong cash flow and expect to be able to stay within cash flow for our identified drilling program. We are moving forward with confidence and enthusiasm about our organic growth opportunities as well as our solid development projects in 2013. With the continued help of the nearly 340 dedicated employees of W&T, I expect 2013 to be a pivotal and profitable year.

Tracy W. Krohn

TRACY W. KROHN,
Chief Executive Officer

The people of W&T tell you how.

"Just a few years ago, W&T was primarily focused on Gulf of Mexico shelf operations with a limited presence in the deep water. By the end of 2012, we had more than 480,000 gross acres in the deep water and over 221,000 gross acres onshore alongside our shelf properties. Growth and diversification was accomplished by our experienced staff. The flexibility to shift personnel to meet the needs of the Company has been instrumental in maintaining our high levels of success."

Steve Freeman, *Vice President, Land and Business Development*

MWORK

"A lot of us here at W&T, grew up in and around the Gulf of Mexico and value its beauty and the important role it has played in our lives. Protecting its waters, shores and marine life is of utmost importance to us and so our concern for the safety of our people and protecting our environment are absolutely our top priority." **Michael Melancon,** *Production Engineer*

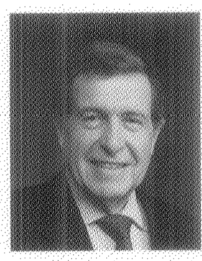
"Management owns over 53% of the Company which insures that we stay aligned with our stakeholders."

Mark Brewer, *Manager, Investor Relations*

"W&T has consistently acquired and developed high quality properties, while attracting talented personnel through its recruiting and training efforts. Our team of experienced, dedicated professionals who are willing and ready to adapt to a changing oil and gas environment is one of our premier assets." **Karen Acree,** *Vice President, Controller*

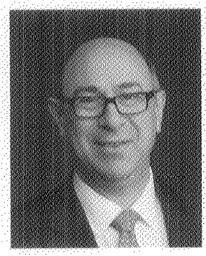
BOARD OF DIRECTORS

VIRGINIA BOULET, has served on our board since March 2005. Ms. Boulet serves as special counsel to the law firm of Adams & Reese, LLP, and is an adjunct professor of law at Loyola University School of Law. She has over twenty years of experience in mergers and acquisitions, equity securities offerings, general business matters and counseling clients regarding compliance with federal securities laws and regulations. Ms. Boulet, graduated from Yale University in 1975 and received her Juris Doctorate, cum laude, Order of the Coif, in 1983 from Tulane University Law School. Ms. Boulet currently serves on the Board of Directors for Century Link, Inc., a telecommunications company. She also serves as chair of the nominating and corporate governance committee for Century Link, as well as being a member of the board's compensation committee.

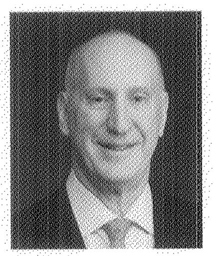


SAMIR G. GIBARA was elected to the board in 2008. Mr. Gibara is the retired Chairman of the Board of the The Goodyear Tire & Rubber Company ("Goodyear"). He also served as CEO of Goodyear from 1996 through 2002. Mr. Gibara is a graduate of Cairo University and holds an M.B.A. from Harvard University. Mr. Gibara also attended the Kellogg Graduate School of Management at Northwestern University. Mr. Gibara has served on the board of directors for Edgen Group Inc. since May of 2012. He is also the current Chairman of the audit committee and a member of the nominating and corporate governance committee for the Edgen Group. In the past, he has served on the boards of directors of Goodyear, Sumitomo Rubber Industries, International Paper Company and Dana Corp.

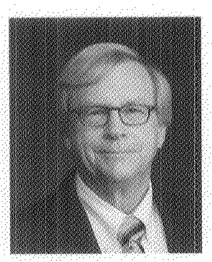
ROBERT I. ISRAEL, was elected to the board in 2007. Mr. Israel is currently the Managing Partner of One Stone Energy Partners, a private equity fund focused on investments in the Oil and Gas industry in the United States and abroad. Mr. Israel was formerly a partner at Compass Advisers, LLP. Prior to joining Compass in 2000, he was the head of the Energy Department of Schroder & Co., Inc. from 1991 to 2000. Mr. Israel holds an M.B.A. from Harvard Business School and a B.A. from Middlebury College. He is currently on the board of Randgold Resources Limited, an African-based gold mining company, and several non-public energy related companies.



STUART B. KATZ, previously served on the Board from 2002 to 2008. Since 2007, Mr. Katz has served as Chief Executive Officer and a member of the Board of Directors of Alconox, Inc., a private company engaged in the manufacturing and marketing of specialty chemicals. From 2001 to 2010, Mr. Katz was a Managing Director of Jefferies Capital Partners ("JCP"), a private equity investment fund. In 2002, Mr. Katz joined the Board in connection with JCP's investment in the Company. In May 2008, Mr. Katz declined to stand for reelection to the Board in connection with JCP's divestment of its remaining equity interest in the Company. Prior to joining JCP in 2001, Mr. Katz had been an investment banker with Furman Selz LLC and its successors for over 16 years. Mr. Katz received a B.S. in engineering from Cornell University and a J.D. from Fordham Law School. Mr. Katz is a member of the bar of the State of New York.



TRACY W. KROHN, has served as Chief Executive Officer since he founded the Company in 1983, as President from 1983 to 2008, as Chairman of the Board of Directors since 2004 and as board Treasurer from 1997 until 2006. Prior to founding W&T, Mr. Krohn was a senior engineer with Taylor Energy. From 1996 to 1997, Mr. Krohn was also Chairman and Chief Executive Officer of Aviara Energy Corporation in Houston, Texas. In 2013, Mr. Krohn was appointed to serve on the board of directors of the American Petroleum Institute. He began his career as a petroleum engineer and offshore drilling supervisor with Mobil Oil Corporation. He graduated with a B.S. in Petroleum Engineering from Louisiana State University in 1978.



S. JAMES NELSON, JR., has served on the board since January 2006. Mr. Nelson retired in 2004 from Cal Dive International, Inc., a marine contractor and operator of offshore oil and gas properties and production facilities, where he was a founding shareholder, Chief Financial Officer, Vice Chairman and Director. From 1985 to 1988, Mr. Nelson was the Senior Vice President and Chief Financial Officer of Diversified Energies, Inc. From 1980 to 1985, Mr. Nelson served as Chief Financial Officer of Apache Corporation, an oil and gas exploration and production company. In addition to his offshore operations experience, Mr. Nelson brings with him an extensive accounting background. From 1966 to 1980, Mr. Nelson was employed with Arthur Andersen & Co. where, from 1976 to 1980, he was a partner serving on the firm's worldwide oil and gas industry team. He received a B.S. in Accounting from Holy Cross College and a M.B.A from Harvard University. Mr. Nelson is also a Certified Public Accountant. Additionally, since 2004 Mr. Nelson has served on the Boards of Directors and audit committees of Oil States International, Inc., a diversified oilfield services company, and ION Geophysical, a seismic services provider. From 2005 until the company's sale in 2008, he was a member of the board of directors and compensation and audit committees of Quintana Maritime Ltd., an international provider of dry bulk cargo marine transportation services based in Athens, Greece. Mr. Nelson has also served from 2010 to 2012 as a member of the board of directors and the audit and compensation committees of Genesis Energy, LP, a midstream master limited partnership.

B. FRANK STANLEY, was appointed to the board in 2009. He is currently Co-Chief Executive Officer and Chief Financial Officer of Retail Concepts, Inc., a privately-held retail chain of 30 stores in 13 states. Prior to joining Retail Concepts, Inc. in 1998, he was Chief Financial Officer of Southpoint Porsche Audi WGW Ltd.from 1987 to 1988. From 1985 to 1987, he was employed by KPMG Peat Marwick, holding the position of Manager, Audit in 1987. From 1983 to 1984, he was Chief Financial Officer of Design Research, Inc., a manufacturer of housing for offshore drilling platforms. From 1980 to 1982, he was Chief Financial Officer of Tiger Oilfield Rental Co., Inc and from 1977 to 1979, he was an accountant with Trunkline Gas Co. Mr. Stanley holds a B.B.A. in Accounting from Texas A&M University and is a certified public accountant.

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

Form 10-K

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

For the fiscal year ended December 31, 2012

or

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

For the transition period from to

Commission File Number 1-32414

W&T OFFSHORE, INC.
(Exact name of registrant as specified in its charter)

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

(713) 626-8525
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.00001	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

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

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

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

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

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

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐

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

The aggregate market value of the registrant's common stock held by non-affiliates was approximately $529,519,000 based on the closing sale price of $15.30 per share as reported by the New York Stock Exchange on June 29, 2012.

The number of shares of the registrant's common stock outstanding on February 25, 2013 was 75,249,630.

DOCUMENTS INCORPORATED BY REFERENCE

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

W&T OFFSHORE, INC.
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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate under the circumstances. Known material risks that may affect our financial condition and results of operations are discussed in Item 1A, Risk Factors, and market risks are discussed in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, of this Annual Report on Form 10-K and may be discussed or updated from time to time in subsequent reports filed with the Securities and Exchange Commission ("SEC"). Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date made. We assume no obligation, nor do we intend, to update these forward-looking statements, unless required by law. Unless the context requires otherwise, references in this Annual Report on Form 10-K to "W&T," "we," "us," "our" and the "Company" refer to W&T Offshore, Inc. and its consolidated subsidiaries.

PART I

Item 1. *Business*

W&T Offshore, Inc. is an independent oil and natural gas producer, active in the exploration, development and acquisition of oil and natural gas properties primarily in the Gulf of Mexico and Texas. W&T Offshore, Inc. is a Texas corporation originally organized as a Nevada corporation in 1988, and successor by merger to W&T Oil Properties, Inc., a Louisiana corporation organized in 1983.

The Gulf of Mexico is an area where we have developed significant technical expertise and where high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve a rapid return on our invested capital. We have leveraged our historic experience in the conventional shelf (water depths of less than 500 feet) to develop higher impact capital projects in the Gulf of Mexico in both the deepwater (water depths in excess of 500 feet) and the deep shelf (well depths in excess of 15,000 feet and water depths of less than 500 feet). We have acquired rights to explore and develop new prospects and acquired existing oil and natural gas properties in both the deepwater and the deep shelf, while at the same time continuing our focus on the conventional shelf.

During 2011, we significantly increased our activity onshore from what was previously a relatively minor presence. In May 2011, we acquired various properties and leasehold interests in four counties in the Permian Basin of West Texas (as described below) in a single transaction and separately acquired other leasehold interests in another county in the Permian Basin. In East Texas, we acquired leasehold interests in 2011 and have been evaluating this area through selective exploration and development activities.

As of December 31, 2012, we have interests in offshore leases covering approximately 1.2 million gross acres (0.8 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. Onshore, we have leasehold interests in approximately 0.2 million gross acres (0.2 million net acres), substantially all of which are in Texas. Approximately 54% of our total net offshore acreage is developed and approximately 11% of our total net onshore acreage is developed. Of the onshore leasehold acreage classified as undeveloped, a substantial portion could expire in 2013 but is expected to be extended by drilling two additional wells in 2013 and can be further extended by additional operations or production in future years.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent petroleum consultant, our total proved reserves at December 31, 2012 were 117.5 million barrels of oil equivalent ("MMBoe") or 705.1 billion cubic feet equivalent ("Bcfe"). Approximately 53% of our reserves were classified as proved developed producing, 21% as proved developed non-producing and 26% as proved undeveloped. Classified by product, our reserves at December 31, 2012 were 47% oil, 13% natural gas liquids ("NGLs") and 40% natural gas. These percentages were determined using the energy-equivalent ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. This energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for oil, NGLs and natural gas may differ significantly. Our total proved reserves had an estimated present value of future net revenues discounted at 10% ("PV-10") of $2.8 billion. Our PV-10 after considering future cash outflows related to asset retirement obligations ("ARO") and without deducting future income taxes was $2.5 billion, and our standardized measure of discounted future cash flows was $1.8 billion as of December 31, 2012. For additional information about our proved reserves and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows, see *Properties – Proved Reserves* under Part I, Item 2 of this Form 10-K.

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

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

In May 2011, we acquired from Opal Resources LLC and Opal Resources Operating Company LLC (collectively, "Opal") certain oil and gas leasehold interests in the Permian Basin of West Texas, which we refer to as our "Yellow Rose Properties." Internal estimates of proved reserves associated with the Yellow Rose Properties as of the acquisition date were approximately 30.1 MMBoe (180.4 Bcfe), comprised of approximately 69% oil, 22% NGLs and 9% natural gas, and approximately 70% of such reserves were classified as proved undeveloped.

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

From time to time, as part of our business strategy, we sell various properties. In 2012, we sold our 40%, non-operated working interest in the South Timbalier 41 field located in the Gulf of Mexico. In 2011 and 2010, there were no property sales of significance.

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

Our exploration efforts historically have been in areas in reasonably close proximity to known proved reserves, but in 2013, some of our planned exploration projects are higher risk with potentially higher returns than our historical risk/reward profile. Historically, we have financed our drilling capital expenditures with operating cash flow. The investment associated with drilling an offshore well and future development of an offshore project principally depends upon water depth, the depth of the well, the complexity of the geological formations involved and whether the well or project can be connected to existing infrastructure or will require additional investment in infrastructure. Deepwater and deep shelf drilling projects can be substantially more capital intensive than those on the conventional shelf and onshore. Certain risks are inherent in the oil and natural gas industry and our business, any one of which, if it occurs, can negatively impact our rate of return on shareholders' equity. When projects are extremely capital intensive and involve substantial risk, we often seek participants to share the risk. Onshore wells are less capital intensive than offshore wells, but the amount of reserves discovered and developed on a per well basis has historically been less from onshore wells than from offshore wells. We drilled four, eight and six successful offshore wells (gross) in 2012, 2011 and 2010, respectively and drilled 77 and 39 successful onshore wells (gross) in 2012 and 2011, respectively.

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

Our total capital expenditure budget for 2013 currently is $450.0 million, not including any potential acquisitions. The budget includes 63% for exploration and 37% for development and these percentages include amounts for facilities capital, recompletions, seismic and leasehold items. Geographically, the budget includes 63% for offshore (11 wells) and 37% for onshore. The budget for offshore includes two deepwater wells and a joint interest arrangement in another deepwater well, of which we are not the operator. The budget for onshore includes 27 wells in the Yellow Rose Properties and amounts currently designated for our Terry County and East Texas prospects for completion work and additional wells, which require further evaluation. Thus far in 2013, we have not closed any acquisitions, but we continue to evaluate and bid on opportunities as they arise. We anticipate funding our 2013 capital budget and any potential acquisitions with cash flow from operating activities, cash on hand, borrowings under our revolving bank credit facility and by accessing the capital markets to the extent necessary. Our 2013 capital budget is subject to change as conditions warrant. We strive to be as flexible as possible and believe this strategy holds the best promise for value creation and growth and managing the volatility inherent in our business.

Business Strategy

We plan to continue to acquire, explore and develop oil and natural gas reserves on the Outer Continental Shelf ("OCS"), the area of our historical success and technical expertise, which we believe will yield 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 volatility and, more specifically, the significant decline in natural gas prices during the past several years, we also believe that other less well-capitalized producers may seek buyers for their properties both onshore and offshore, which could create opportunities for us.

We believe a portion of our Gulf of Mexico acreage has exploration potential below currently producing zones, including deep shelf reserves at subsurface depths greater than 15,000 feet. Although the cost to drill deep shelf wells is usually significantly higher than shallower wells, the reserve targets are typically larger and the use of existing infrastructure, when available, can increase the economic potential of these wells.

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

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

Competition

The oil and natural gas industry is highly competitive. We currently operate in the Gulf of Mexico and onshore in Texas and compete for the acquisition of oil and natural gas properties primarily on the basis of price for such properties. We compete with numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well established companies and have financial and other resources substantially greater than ours. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. For a more thorough discussion of how competition could impact our ability to successfully complete our business strategy, see *Risk Factors* in Part I, Item 1A of this Form 10-K.

Oil and Natural Gas Marketing and Delivery Commitments

We sell our oil, NGLs and natural gas to third-party purchasers. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers. However, in 2012 approximately 35% of our sales were to Shell Trading (US) Co. and approximately 16% of our sales were to ConocoPhillips Company and Phillips66 Company on a combined basis, which became separate companies during 2012. See *Financial Statements – Note 1 – Significant Accounting Policies – Concentration of Credit Risk* in Part II, Item 8 of this Form 10-K for additional information about our sales to customers. Due to the nature of oil and natural gas markets and because oil and natural gas are freely traded commodities with numerous purchasers in the Gulf of Mexico and Texas, we do not believe the loss of a single purchaser or a few purchasers would materially affect our ability to sell our production. We do not have any agreements which obligate us to deliver material quantities to third parties.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission ("FERC") regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and NGLs can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

In addition, the Federal Trade Commission, the FERC and the Commodity Futures Trading Commission ("CFTC") hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

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

Similarly, the natural gas pipeline industry may also be subject to state regulations which may change from time to time. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 ("Competition Bill") and H.B. 1920 ("LUG Bill"). The Competition Bill gives the Railroad Commission of Texas ("RRC") the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Bill modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007. The RRC was subject to a sunset condition. Although certain proposals were made in 2012, no legislation was enacted during 2012. The RRC will be reviewed again in 2013.

The Outer Continental Shelf Lands Act ("OCSLA"), which is administered by the Bureau of Ocean Energy Management ("BOEM") and the FERC, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of the FERC's principal goals in carrying out OCSLA's mandate is to increase transparency in the market to provide producers and shippers working in the OCS with greater assurance of open access service on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines. On June 18, 2008, the BOEM issued a final rule, effective August 18, 2008, that implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines on the OCS.

In December 2007, the FERC issued rules ("Order 704") requiring that any market participant, including a producer such as W&T, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million British thermal units ("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, the BOEM or state regulators will take on these matters; however, we do not believe that any such action taken will affect us differently, in any material way, than other natural gas producers with which we compete.

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

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

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

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

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

To cover the various obligations of lessees on the OCS, the BOEM generally requires that lessees 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. W&T Offshore, Inc. is currently exempt from supplemental bonding requirements by the BOEM. As many BOEM regulations are being reviewed, we may be subject to supplemental bonding requirements in the future. Under some circumstances, the BOEM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations. See *Risk Factors – BP's Deepwater Horizon explosion and ensuing oil spill could have broad adverse consequences affecting our operations in the Gulf of Mexico, some of which may be unforeseeable* under Part I, Item 1A in this Form 10-K for more information.

The Office of Natural Resources Revenue ("ONRR") administers the collection of royalties under the terms of the OCSLA and the oil and natural gas leases issued thereunder. The amount of royalties due is based upon the terms of the oil and natural gas leases as well as the regulations promulgated by the ONRR and the BOEM.

Hurricanes in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past hurricanes have included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEM and the BSEE continue to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEM and the BSEE have periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, requirements will be issued by the BOEM and the BSEE for future hurricane seasons. New requirements, if any, could increase our operating costs and/or capital expenditures.

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 in the Gulf of Mexico may require us to incur significant costs. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

We believe we are in substantial compliance with current applicable environmental laws and regulations. We believe that compliance with existing requirements will not have a material adverse impact on our operations, but failure to comply could have material consequences. 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 related to compliance with environmental laws and regulations 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 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.

Air emissions from our operations are subject to the Clean Air Act ("CAA") and comparable state and local requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In August 2012, the U.S. Environmental Protection Agency (the "EPA") adopted new rules that establish air emission controls requirements for oil and natural gas production and natural gas processing operations. Specifically, the EPA established New Source Performance Standards for emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards for hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA rules require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent any hydrocarbons that come to the surface during completion of the fracturing process. The requirement for flaring of gas not sent to a gathering line became effective October 15, 2012, and all operators are required to use "green completions" drilling equipment beginning January 1, 2015. The rules also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants. These rules may require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our operating results. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, such as petroleum refineries, on an annual basis effective in 2011, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. We believe we are in compliance with this new emission reporting requirement as it applies to our operations

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

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil, NGLs and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The primary federal law for oil spill liability is the Oil Pollution Act (the "OPA") which amends and augments oil spill provisions of the Clean Water Act. OPA imposes certain duties and liabilities on "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters, including the OCS or adjoining shorelines. A liable "responsible party" includes the owner or operator of an onshore facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several, strict liability, without regard to fault, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the OCS, although the Secretary of Interior may increase this amount up to a maximum of $150 million. We are currently required to demonstrate, on an annual basis, that we have ready access to $150 million that can be used to respond to an oil spill from our facilities on the OCS. As a result of the BP Deepwater Horizon incident, legislation has been proposed in Congress to increase the minimum level of financial responsibility to $300 million or more. If OPA is amended to increase the minimum level of financial responsibility to $300 million, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if an oil discharge or substantial threat of discharge were to occur, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Hurricane Remediation and Insurance Claims* in Part II, Item 7 of this Form 10-K for additional information on insurance coverage.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. Effective February 1, 2012, the RRC began requiring all operators to disclose on a public website the chemical ingredients and water volumes used to hydraulically fracture wells in Texas. We follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities including disclosure requirements. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells that require hydraulic fracturing.

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

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 include regulations regarding the taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species). The BSEE also issues numerous regulations under the nomenclature Notice to Lessees ("NTL") that provide formal guidelines on implementation of OCS regulations and standards. We believe we are in compliance in all material respects with the requirements regarding protection of marine species.

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

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 regulations issued by the National Oceanic and Atmospheric Administration. Unique regulations related to operations in a sanctuary include prohibition of drilling activities within certain protected areas, restrictions on the types of water and other substances that may be discharged, required depths of discharge in connection with drilling and production activities and limitations on mooring of vessels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the National Environmental Policy Act, the Coastal Zone Management Act, the Emergency Planning and Community Right-to-Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Magnuson-Stevens Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands. These and other protected areas may require certain mitigation measures to avoid harm to wildlife, and such laws and regulations may impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. Naturally Occurring Radioactive Materials ("NORM") may contaminate minerals extraction and processing equipment used in the oil and natural gas industry. The waste resulting from such contamination is regulated by federal and state laws. Standards have been developed for worker protection; treatment, storage and disposal of NORM and NORM waste; management of 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 liability insurance and well control insurance for all of our operations. In addition, we maintain property and hurricane damage insurance coverage for some, but not all, of our properties, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain does not cover the risks described above from gradual pollution events which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover such risks or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant environmental event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

Seasonality

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

Employees

As of December 31, 2012, we employed 337 people. We are not a party to any collective bargaining agreements and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Additional Information

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

Item 1A. *Risk Factors*

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

Risks Relating to the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil, NGLs and natural gas prices may adversely affect our business, financial condition, cash flow, liquidity or results of operations and our ability to meet our capital expenditure obligations and financial commitments and to implement our business strategy.

The price we receive for our oil, NGLs and natural gas production directly affects our revenues, profitability, access to capital and future rate of growth. Oil, NGLs and natural gas are commodities and are subject to wide price fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, NGLs and natural gas have been volatile and will likely continue to be volatile in the future. The prices we receive for our production and the volume of our production depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil, NGLs and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil, NGLs, natural gas and liquefied natural gas;

- acts of war, terrorism or political instability in oil producing countries;
- economic conditions;
- political conditions and events, including embargoes, affecting oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil, NGLs and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- geographic differences in pricing.

Lower prices for our oil, NGLs and natural gas production may not only decrease our revenues on a per unit basis but may also reduce the amount of oil, NGLs and natural gas that we can produce economically. For example, the prices of oil and natural gas declined substantially during the second half of 2008 and impacted production volumes. Natural gas and NGLs prices have been negatively affected by excess natural gas production, high levels of stored natural gas and weather conditions affecting demand. There have been significant recent development activities in shale and other resource plays, which have the potential to yield a significant amount of natural gas and NGLs production, as well as natural gas and NGLs produced in connection with increased domestic oil drilling activities. The potential increases in natural gas supplies resulting from the large-scale development of these unconventional resource reserves could continue to have an adverse impact on the price of natural gas and NGLs. An environment of depressed oil, NGLs and natural gas prices would materially and adversely affect our future business, financial condition, results of operations, liquidity and/or ability to finance planned capital expenditures.

If oil, NGLs and natural gas prices decrease, we may be required to write down the carrying values and/or the estimates of total reserves of our oil and natural gas properties.

Accounting rules applicable to us require that we periodically review the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. 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. We did not have any impairment write-downs in 2012, 2011 or 2010. Declines in oil, NGLs and natural gas prices after December 31, 2012 may require us to record additional ceiling test impairments in the future. No assurance can be given that we will not experience a ceiling test impairment in future periods, which could have a material adverse effect on our results of operations in the period taken. As a result of lower oil, NGLs and natural gas prices, we may also reduce our estimates of the reserves that may be economically recovered, which would reduce the total value of our proved reserves. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Impairment of oil and natural gas properties* in Part II, Item 7 and *Financial Statements – Note 1 – Significant Accounting Policies* in Part II, Item 8 of this Form 10-K for additional information on the ceiling test.

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

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

The Company is responding to a qui tam action filed under the Federal False Claims Act which could have a material adverse effect upon us.

On September 21, 2012, we were served with a complaint in a *qui tam* action filed under the federal False Claims Act by an employee of a Company contractor. The lawsuit, *United States ex rel. Comeaux v. W&T Offshore, Inc., et al.; CA No. 10-494*, was filed in the United States District Court for the Eastern District of Louisiana, against the Company and three other working interest owners related to claims associated with three of the Company's operated production platforms. A *qui tam* action, also known as a "whistleblower" action, is a lawsuit brought by a private citizen seeking civil penalties or damages against a person or company on behalf of the government for alleged violations of law. If the claims are successful, the person filing the suit may recover a percentage of the damages or penalty from the lawsuit as a reward for exposing a wrongdoing and recovering funds on behalf of the government. The complaint was originally filed in 2010 but kept under confidential seal in order for the federal government to decide if it wished to intervene and take over the prosecution of the *qui tam action*. The government declined to intervene in this suit and the complaint was unsealed and made public in June 2012, thereby giving the plaintiff the opportunity to pursue the claims on behalf of the government.

The complaint alleges that environmental violations at three of our operated production platforms in the Gulf of Mexico violate the federal offshore lease provisions so that we, among other things, wrongfully retained benefits under the applicable leases. The alleged environmental violations include allegations of discharges of relatively small amounts of oil into the Gulf of Mexico, the failure to report and record such discharges, and falsification of certain produced water samples and related reports required under federal law. The events are alleged to have occurred in 2009. These are largely the same allegations involved in the federal grand jury investigation described above. We have filed a motion to dismiss the claim. The plaintiff dismissed his claims against the three other working interest owners after they filed motions to dismiss. The plaintiff conceded that certain of his claims should be dismissed in his reply to the Company's motion to dismiss. The motion remains pending before the court.

The Company has been sued by certain landowners alleging damages to their properties.

Since 2009, certain Cameron Parish landowners have filed suits in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and Tracy W. Krohn as well as several other defendants unrelated to us. In their lawsuits, plaintiffs are alleging that property they own has been contaminated or otherwise damaged by the defendants' oil and gas exploration and production activities and are seeking compensatory and punitive damages. During 2012, we settled claims with certain landowners and paid $10.0 million. We assessed the remaining claims to be probable and have accrued $1.3 million in our contingent liabilities as of December 31, 2012. However, we cannot state with certainty that our estimates of additional exposure are accurate concerning this matter.

BP's Deepwater Horizon explosion and ensuing oil spill could have broad adverse consequences affecting our operations in the Gulf of Mexico, some of which may be unforeseeable.

In April 2010, there was a fire and explosion aboard the Deepwater Horizon drilling platform operated by BP in the deep water of the Gulf of Mexico. As a result of the explosion and ensuing fire, the rig sank, causing loss of life, and created a major oil spill that produced economic, environmental and natural resource damage in the Gulf Coast region. In response to the explosion and spill, there have been many proposals, and substantial rules adopted, by governmental and private constituencies to address the direct impact of the disaster and to prevent similar disasters in the future. Beginning in May 2010, the BOEM and BSEE issued a series of NTLs imposing a variety of new safety measures and permitting requirements. They also imposed a six-month moratorium on drilling activities in federal offshore waters that stretched into a much longer moratorium resulting in delays in not only deepwater drilling but also in many other types of activities in the Gulf of Mexico that continue to exist currently.

In addition to the drilling restrictions, new safety measures and permitting requirements already issued by the BOEM and BSEE, there have been numerous additional proposed changes in laws, regulations, guidance and policy in response to the Deepwater Horizon explosion and oil spill that could affect our operations and cause us to incur substantial losses or expenditures. Implementation of any one or more of the various proposed responses to the disaster could materially adversely affect operations in the Gulf of Mexico by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory costs, and, further, could lead to a wide variety of other unforeseeable consequences that make operations in the Gulf of Mexico more difficult, more time consuming, and more costly. For example, a variety of amendments to the OPA have been proposed in response to the Deepwater Horizon incident. OPA and regulations adopted pursuant to OPA impose a variety of requirements related to the prevention of and response to oil spills into waters of the United States, including the OCS, which includes the Gulf of Mexico where we have substantial offshore operations. OPA subjects operators of offshore leases and owners and operators of oil handling facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. OPA also requires operators to provide evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. We are currently required to demonstrate, on an annual basis, that we have ready access to $150 million that can be used to respond to an oil spill from our facilities on the OCS. Legislation has been proposed in Congress to amend OPA to increase the minimum level of financial responsibility to $300 million or more. If the minimum level of financial responsibility is increased further, we may experience difficulty in providing financial assurances sufficient to comply with the revised requirement. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased further.

Other significant regulatory changes since the Deepwater Horizon event are regulations related to assessing the potential environmental impact of future spills using worse case discharge scenarios on a well-by-well basis, spill response documentation, compliance reviews, operator practices related to safety and implementing a safety and environmental management system. The new regulations and increased review process increases the time it takes to obtain drilling permits and increases the cost of operations. As these new regulations and guidance continue to evolve, the risk to our business may be increased. The permitting process is slower and inconsistent for deep water work, shallow water work and even for plug and abandonment activities. This could lead to increased costs and performing work at less than optimal effectiveness. We have not experienced delays in obtaining permits related to our onshore operations.

Regulatory requirements, NTLs and permitting procedures imposed by the BOEM and BSEE could significantly delay our ability to obtain permits to drill new wells in offshore waters.

Subsequent to the BP Deepwater Horizon incident in the U.S. Gulf of Mexico in April 2010, the BOEM and BSEE issued a series of NTLs imposing new requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. These new requirements include the following:

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

As a result of the issuance of these new NTLs and the new regulatory requirements, the BOEM has been taking longer to review and approve permits for new wells than was common prior to the Deepwater Horizon incident. These NTLs also increase the cost of preparing each permit application and will increase the cost of each new well, particularly for wells drilled in deeper waters on the OCS. The delay in granting permits could also cause some of our leases to lapse as a result of failure to commence drilling or continue production operations.

New requirements imposed by the BOEM and BSEE could significantly impact the cost of operating our business.

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

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

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

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

As of December 31, 2012, available borrowings under our revolving bank credit facility are currently limited to $725.0 million, less outstanding borrowings and letters of credit. Availability is determined semi-annually by our lenders and is based on oil, NGLs and natural gas prices and on our proved reserves. Substantially all of our oil and natural gas properties are pledged as collateral under the credit agreement governing our revolving bank credit facility (the "Credit Agreement"). The Credit Agreement limits our ability to incur additional indebtedness based on specified financial covenants, ratios or other criteria. Lower oil, NGLs and natural gas prices in the future could result in a reduction in credit availability and also affect our ability to satisfy these covenants, ratios or other criteria and thus could reduce our ability to incur additional indebtedness and our ability to replace reserves.

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

We could be exposed to uninsured losses in the future. The occurrence of a significant accident or other event not covered in whole or in part by our insurance could have a material adverse impact on our financial condition and operations. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. In May and June 2012, we renewed our insurance policies covering well control and hurricane damage at an annual cost of approximately $30.6 million. A retention amount of $5.0 million for well control events and $40.5 million per hurricane occurrence must be satisfied by us before we are indemnified for losses. In addition, pollution and environmental risks are generally not fully insurable as gradual seepage and pollution are not covered under our policies. Because third-party drilling contractors are used to drill our wells, we may not realize the full benefit of workmen's compensation laws in dealing with their employees. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented.

See *Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims and – Note 18 – Contingencies* under Part II, Item 8 of this Form 10-K for additional information on legal issues regarding our insurance coverage.

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

Due to insurance claims in recent years associated with hurricanes in the Gulf of Mexico and global catastrophic losses, property damage and well control insurance coverage has become more limited and the cost of such coverage has become both more costly and more volatile. The insurance market may change dramatically in the future due to the major oil spill that occurred in 2010 at BP's Macondo well in the deepwater Gulf of

Mexico. As of December 31, 2012, approximately 91% of our PV-10 value of proved reserves attributable to our Gulf of Mexico properties is on platforms that are covered under our current insurance policies for named windstorm damage. Our insurers may not continue to offer us the type and level of our current coverage, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurance companies will not pay our claims. The occurrence of any or all of these possibilities could have a material adverse effect on our financial condition and results of operations. 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.

Commodity derivative positions may limit our potential gains.

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

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

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

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

Current SEC guidance requires proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Further, if we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may have to write off reserves previously recognized as proved undeveloped.

As of December 31, 2012, approximately 26% of our total proved reserves were undeveloped and approximately 21% of our total proved reserves were developed non-producing. There can be no assurance that all of those reserves will ultimately be developed or produced.

We are not the operator with respect to approximately 14% of our proved developed non-producing reserves, so we may not be in a position to control the timing of all development activities. Furthermore, there can be no assurance that all of our undeveloped and developed non-producing reserves will ultimately be produced during the time periods we have planned, at the costs we have budgeted, or at all, which could result in the write-off of previously recognized reserves.

If we are not able to replace reserves, we will not be able to sustain production at current levels.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful exploration, development or acquisition activities, our proved reserves and production will decline over time. By their nature, estimates of undeveloped reserves are less certain. Recovery of undeveloped reserves could require significant capital expenditures and successful drilling operations. Our future oil and natural gas reserves, production, and therefore our cash flow and net income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

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

Unless we conduct successful development and exploration activities at sufficient levels or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves during the initial few years of production. The majority of our current production is from the Gulf of Mexico. Production from reservoirs in the Gulf of Mexico generally decline more rapidly than from reservoirs in many other producing regions of the United States. Our independent petroleum consultant estimates that, on average, 43% of our total proved reserves are depleted within three years. As a result, our need to replace reserves and production from new investments is relatively greater than that of producers who recover lower percentages of their reserves over a similar time period, such as those producers who have a larger portion of their reserves in areas other than the Gulf of Mexico. We may not be able to develop, find or acquire additional reserves in sufficient quantities to sustain our current production levels or to grow production beyond current levels. In addition, due to the significant time requirements involved with exploration and development activities, particularly for wells in the deepwater or wells not located near existing infrastructure, actual oil and natural gas production from new wells may not occur, if at all, for a considerable period of time following the commencement of any particular project.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures and acquisitions with cash on hand, cash provided by operating activities, securities offerings and bank borrowings. In order to finance future capital expenditures, we may need to alter or increase our capitalization substantially through the issuance of additional debt or equity securities, bank borrowings, reserve-based loans, joint ventures or other means. These changes in capitalization may significantly affect our financial risk profile.

Future cash flows are subject to a number of variables, such as the level of production from existing wells, the prices of oil, NGLs and natural gas, and our success in developing and producing new reserves. Any reductions in our capital expenditures to stay within internally generated cash flow (which could be adversely affected by declining commodity prices) and cash on hand will make replacing produced reserves more difficult. If our cash flow from operations and cash on hand are not sufficient to fund our capital expenditure budget, we may not be able to access additional debt, equity or other methods of financing on an economic or timely basis to replace our proved reserves.

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

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil, NGLs and natural gas and securing trained personnel. Many of our competitors have financial resources that allow them to obtain substantially greater technical expertise and personnel than we have. We actively compete with other companies in our industry when acquiring new leases or oil and natural gas properties. For example, new leases acquired from the BOEM are acquired through a "sealed bid" process and are generally awarded to the highest bidder. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our competitors may also be able to pay more for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay. On the acquisition opportunities made available to us, we compete with other companies in our industry for such properties through a private bidding process, direct negotiations or some combination thereof. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the divesting practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors we cannot control or influence.

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

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

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

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

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

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

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

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, geological issues and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not assure us that we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells hinder our efforts to replace reserves.

Our oil and natural gas exploration and production activities, including well stimulation and completion activities which include, among other things, hydraulic fracturing, involve a variety of operating risks, including:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as tropical storms, hurricanes and other adverse weather conditions;
- inability to obtain insurance at reasonable rates;
- failure to receive payment on insurance claims in a timely manner, or for the full amount claimed;
- pipe, cement, subsea well or pipeline failures;
- casing collapses or failures;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;

- abnormally pressured formations or rock compaction; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, encountering NORM, and discharges of brine, well stimulation and completion fluids, toxic gases, or other pollutants into the surface and subsurface environment.

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

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

Offshore operations are also subject to a variety of operating risks related to the marine environment, such as capsizing, collisions and damage or loss from tropical storms, hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate funds available for exploration, development and acquisitions or result in the loss of property and equipment.

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

The geographic concentration of our properties along the U.S. Gulf Coast and adjacent waters on and beyond the 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 a majority of our properties could experience the same conditions at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other operators who have properties over a wider geographic area. For example, in 2009, net production of approximately 8.7 Bcfe was deferred as a result of damage caused primarily by Hurricane Ike and, in 2012, Hurricane Isaac resulted in the deferral of approximately 2.9 Bcfe.

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

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

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. We utilize hydraulic fracturing techniques in connection with developing our recently acquired Yellow Rose Properties and other onshore properties. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. The EPA, however, recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA Underground Injection Control Program. In addition, the EPA has commenced a broad study of the potential environmental effects of hydraulic fracturing activities, and the agency has indicated that it expects to issue its study report in late 2014. A number of other federal agencies, including the U.S. Department of Energy, Department of Interior, and White House Council on Environmental Quality, are also studying various aspects of hydraulic fracturing. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Legislation also has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states and local governments have adopted, and other states and local governments are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations, including states in which we operate. For example, effective February 1, 2012, the RRC began requiring all operators to disclose on a public website the chemical ingredients and water volumes used to hydraulically fracture wells in Texas. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to associated permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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

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

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

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

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

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

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

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

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of our reserves at December 31, 2012. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Oil and natural gas reserve quantities, Part II,* Item 7 for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in *Business in* Part I, Item 1, *Properties* in Part I, Item 2 and *Financial Statements – Note 21 – Supplemental Oil and Gas Disclosures* in Part II, Item 8 of this Form 10-K.

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

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

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

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

A prospect is an area of land in which we own an interest, could acquire an interest or have operating rights, and have what our geoscientists believe, based on available seismic and geological information, to be indications of economic accumulations of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure 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, deep shelf and various onshore formations may make it more difficult for us to sustain our historical rates of drilling success. As a result, we can offer no assurance that we will find commercial quantities of oil and natural gas and, therefore, we can offer no assurance that we will achieve positive rates of return on our investments.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities, which in most cases are owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells because of a reduction in demand for our production or because of inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market. We have, in the past, been required to shut in wells when hurricanes have caused or threatened damage to pipelines and gathering stations. For example, in September

2008, as a result of Hurricane Ike, two of our operated platforms and eight non-operated platforms were toppled and a number of platforms, third-party pipelines and processing facilities upon which we depend to deliver our production to the marketplace were damaged. In 2012, under threat of Hurricane Isaac, we shut in most of our offshore production for a period of 10 to 25 days.

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

Currently, a portion of our oil and natural gas is processed for sale on platforms owned by parties with no economic interest in our wells and no other processing facilities would be available to process such oil and natural gas without significant investment by us. In addition, third-party platforms could be damaged or destroyed by hurricanes which could reduce or eliminate our ability to market our production. As of December 31, 2012, 10 fields, accounting for approximately 3.7 Bcfe (or 3.6%) of our 2012 production, are tied back to separate, third-party owned platforms. There can be no assurance that the owners of such platforms will continue to process our oil and natural gas production. If any of these platform operators ceases to operate their processing equipment, we may be required to shut in the associated wells or construct additional facilities.

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

We depend upon third-party pipelines that provide delivery options from our facilities. Because we do not own or operate these pipelines, their continued operation is not within our control. If any of these third-party pipelines become partially or fully unavailable to transport natural gas and oil, or if the gas quality specification for the natural gas pipelines changes so as to restrict our ability to transport natural gas on those pipelines, our revenues could be adversely affected. For example, a third-party pipeline used by our Main Pass 108 field was shut down between June 2010 and March 2011. We estimate this shutdown caused us to defer production of approximately 4.9 Bcfe during 2010 and 3.7 Bcfe during 2011. In 2012, various pipelines were shut down causing production deferral of approximately 1.5 Bcfe with our Matterhorn field being most significantly affected by these shutdowns.

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

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

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

- land use restrictions;
- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plugging and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;

- safety precautions;
- operational reporting;
- reporting of natural gas sales for resale; and
- taxation.

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

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

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

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

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

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

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

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

In 2012 and in prior years, we have been subject to investigations with respect to allegations that we did not comply with applicable environmental laws and regulations. In December 2012, we reached an agreement with respect to the previously disclosed federal grand jury investigation related to certain violations of environmental laws and regulations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and regardless of whether our operations met previous standards in the industry at the time they were conducted. Our permits require that we report any incidents that cause or could cause environmental damages. See *Business – Regulation*, Part I, Item 1 of this Form 10-K for a more detailed description of our environmental risks.

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

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on its findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, such as petroleum refineries, on an annual basis, beginning in 2011, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

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

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

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

On July 21, 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "DF Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The DF Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the DF Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Colombia in September 2012, although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap", "security-based swap", "swap dealer" and "major swap participant". The DF Act and CFTC rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the DF Act and CFTC rules on us and the timing of such effects.

The DF Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The DF Act and regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the DF Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the DF Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the DF Act is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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

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

We face security exposure, including cyber-security exposure, from unauthorized access to our facilities and computer systems. This exposure includes unauthorized access to sensitive information; malicious damage to our facilities, infrastructure, and computer systems; malicious damage to third-party facilities, infrastructure, and computer systems; safety exposure for our employees and contractors; and disruptions of our operations. Although we utilize various procedures and controls to mitigate these exposures, there can be no assurances that these procedures and controls will be sufficient to prevent such events from occurring. Cyber-security exposures in particular are evolving and include malicious software, unauthorized access to confidential data and disruptions to operations that use computers and data systems. We do not carry business interruption insurance. Any of these security breaches could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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

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

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

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

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

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

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

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

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

Risks Related to Financings

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

For 2012 and 2011, world financial markets have been affected from time to time by the instability of the Euro and the uncertainty of some Euro-based countries to repay their debt. In addition, one credit agency downgraded the debt of the U.S. government. These types of events bring uncertainty to the financial markets and may produce volatility and may decrease financing availability.

In recent years, access to financing markets was severely limited at various times. In 2008, prices for oil, NGLs and natural gas had decreased precipitously along with the significant instability that existed in the financial markets during this time. In 2009, the global financial markets and economic conditions were severely distressed. There were concerns, both with respect to bank failures and bank liquidity, as to whether our banks would be able to meet their commitments under credit arrangements in place during that time. These concerns led to very few financing transactions being completed.

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

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

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

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

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

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

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

Our debt obligations could have important consequences. For example, they could:

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

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

Risks Related to Our Principal Shareholder, Tracy W. Krohn

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

Tracy W. Krohn owns and controls 39,562,545 shares of our common stock, representing approximately 52.6% of our voting interests as of February 15, 2013. As a result, Mr. Krohn has the ability to control the outcome of matters that require a simple majority of shareholders for approval and other investors, by themselves, will not be able to affect the outcome of virtually any shareholder vote. Mr. Krohn, subject to any duty owed to our minority shareholders under Texas law, is able to control all matters affecting us, including:

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

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

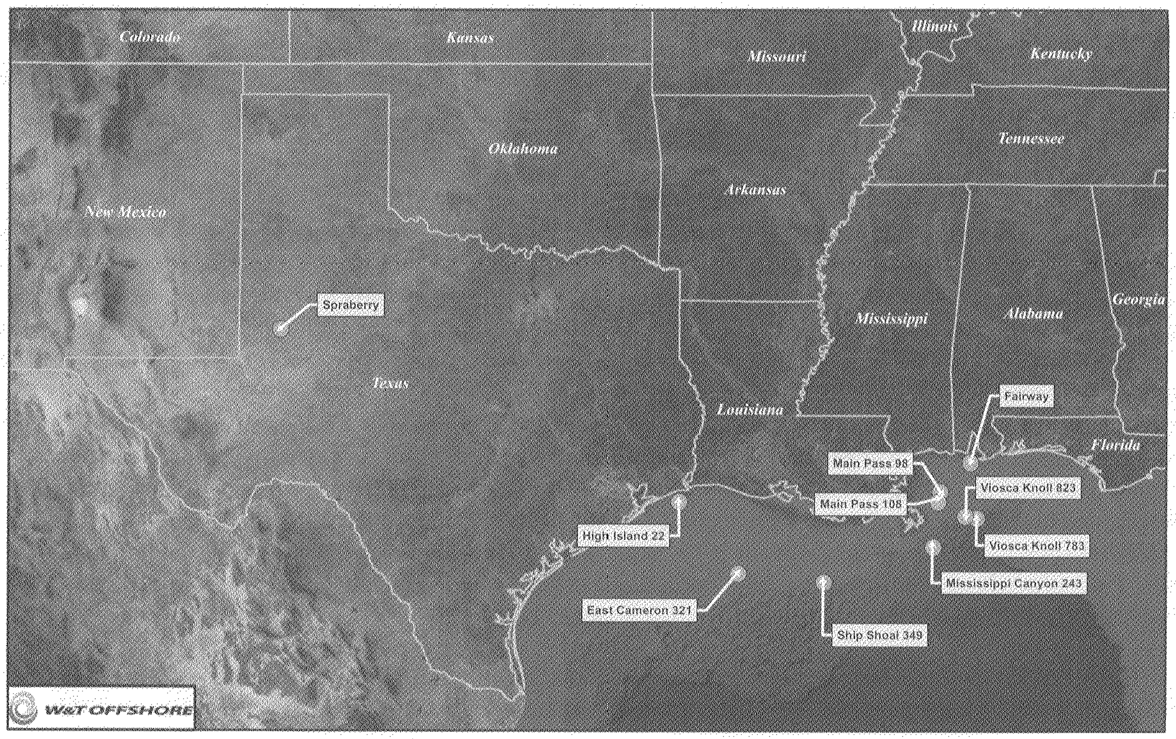
Due to Mr. Krohn's ownership and control, we are exempted from many New York Stock Exchange ("NYSE") corporate governance rules, and, as a result, our other shareholders may not have the protections set forth in those rules, particularly in the event of conflicts of interest with Mr. Krohn.

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

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*



Our fields are located in the Gulf of Mexico, Alabama and Texas. The offshore fields are found in water depths ranging from less than 10 feet up to 4,900 feet. The reservoirs in our offshore fields are generally characterized as having high porosity and permeability, which typically results in high production rates. The reservoirs in our onshore fields are generally characterized as having low porosity and permeability and require stimulation and artificial lift to produce. The following describes our 10 largest fields as of December 31, 2012, based on quantities of proved reserves on a natural gas equivalent basis. At December 31, 2012, these fields accounted for approximately 82% of our proved reserves.

Field Name	Field Category	Operator	Percent Oil and NGLs of Net Reserves (1)	Percent Natural Gas of Net Reserves (1)	2012 Average Daily Equivalent Sales Rate (Mcfe/d) (1)	
					Gross	Net
Spraberry (Yellow Rose Properties)	Onshore	W&T	89%	11%	18,538	15,016
Ship Shoal 349 (Mahogany)	Shelf	W&T	81%	19%	26,937	22,896
Viosca Knoll 783 (Tahoe/SE Tahoe)	Deepwater	W&T	27%	73%	53,053	36,076
Fairway (Fairway Properties)	Shelf	W&T	29%	71%	49,462	27,204
Main Pass 108	Shelf	W&T	19%	81%	27,846	21,442
Miss. Canyon 243 (Matterhorn)	Deepwater	W&T	79%	21%	23,865	23,865
Viosca Knoll 823 (Virgo)	Deepwater	W&T	36%	64%	10,055	6,938
High Island 22	Shelf	W&T	9%	91%	470	390
Main Pass 98	Shelf	W&T	21%	79%	9,431	7,828
East Cameron 321	Shelf	W&T	91%	9%	10,370	8,089

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

Ship Shoal 349 Field (Mahogany).

Ship Shoal 349 field is located off the coast of Louisiana, approximately 235 miles southeast of New Orleans, in 375 feet of water. The field area covers Ship Shoal blocks 349 and 359, with a single production platform on Ship Shoal block 349. Phillips Petroleum Company discovered the field in 1993. We initially acquired a 25% working interest in the field from BP Amoco in 1999. In 2003, we acquired an additional 34% working interest through a transaction with ConocoPhillips that increased our working interest to approximately 59%, and we became the operator of the field in December 2004. In early 2008, we acquired the remaining working interest from Apache Corporation and we now own a 100% working interest in this field. Cumulative field production through 2012 is approximately 31.2 MMBoe gross (187.0 Bcfe gross). This field is a sub-salt development with five productive horizons below salt at depths up to 17,000 feet. As of December 31, 2012, 25 wells have been drilled, 16 of which have been successful. In 2010, we developed a reservoir simulation model to determine the most optimal future development plan. As a result, in 2011, we drilled one development well and one exploration well. In 2012, a third well was drilled and completed as part of an ongoing drilling program and two additional wells were sidetracked. Total proved reserves associated with our interest in this field were 22.7 MMBoe (136.3 Bcfe) at December 31, 2012 and 20.3 MMBoe (121.7 Bcfe) at December 31, 2011.

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

	Year Ended December 31,		
	2012	2011	2010
Net sales:			
Oil (MBbls)	960	445	657
NGLs (MBbls)	85	23	38
Natural gas (MMcf)	2,108	498	863
Total oil equivalent (MBoe)	1,397	551	838
Total natural gas equivalent (MMcfe)	8,380	3,305	5,030
Total oil equivalent (Boe/day)	3,816	1,509	2,297
Total natural gas equivalent (Mcfe/day)	22,896	9,055	13,782
Average realized sales prices:			
Oil ($/Bbl)	$102.55	$101.30	$ 73.20
NGLs ($/Bbl)	41.74	56.06	43.54
Natural gas ($/Mcf)	2.78	4.20	4.88
Oil equivalent ($/Boe)	77.24	87.97	64.33
Natural gas equivalent ($/Mcfe)	12.87	14.66	10.72
Average production costs (1):			
Oil equivalent ($/Boe)	$ 6.27	$ 14.30	$ 13.20
Natural gas equivalent ($/Mcfe)	1.05	2.38	2.20

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

Volume measurements:

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

The following is a description of the remainder of our top 10 properties, measured by proved reserves at December 31, 2012, five of which are located on the conventional shelf and three are located in the deepwater. We do not believe that individually any of these properties are of major significance (each has proved reserves which comprise less than 15% of our total proved reserves, calculated on a natural gas equivalent basis).

Viosca Knoll 783 Field. (Viosca Knoll 783 Lease (Tahoe) and Viosca Knoll 784 Lease (SE Tahoe)) The Viosca Knoll 783 field is located off the coast of Louisiana, approximately 140 miles southeast of New Orleans, in 1,500 to 1,700 feet of water. The field area covers Viosca Knoll blocks 783 and 784, with subsea tiebacks to two platforms in Main Pass 252. Shell discovered the Tahoe prospect in 1984 and the SE Tahoe prospect in 1996. We acquired a 70% working interest in the Tahoe lease and a 100% working interest in the SE Tahoe lease from Shell in 2010. Cumulative field production through 2012 is approximately 31.2 MMBoe gross (187.0 Bcfe gross). The Tahoe prospect is a supra-salt (above the salt layer) development with two productive horizons at depths ranging to 10,300 feet. The SE Tahoe prospect is also a supra-salt development with one productive horizon at a depth of 9,325 feet. As of December 31, 2012, 16 wells have been drilled at the Tahoe prospect, eight of which have been successful and one successful well has been drilled at the SE Tahoe prospect. During December 2012, production from this field, net to our interest, averaged 336 Bbls of oil per day, 1,505 Bbls of NGLs per day and 26,240 Mcf of natural gas per day, for total production of 6,215 Boe per day (37,288 Mcfe per day).

Fairway Field (Fairway Properties). Fairway is comprised of Mobile Bay Area blocks 113 (Alabama State Lease #0531) and 132 (Alabama State Lease #0532) and located in 25 feet of water, approximately 35 miles south of Mobile, Alabama. We acquired our 64.3% working interest, along with operatorship in the Fairway field, from Shell in August 2011. The field was discovered in 1985 with Well 113 #1 (now called JA). Development drilling began in 1990 and was completed in 1991 with the addition of four wells, each drilled from separate surface locations. The five producing wells came on line in late 1991. As of December 31, 2012, six wells have been drilled, one of which was a replacement well. Cumulative field production through 2012 is approximately 112.5 MMBoe gross (674.9 Bcfe gross). This field is a Norphlet sand dune trend development with one producing horizon at an approximate depth of 21,300 feet. During December 2012, production from this field, net to our interest, averaged 17 Bbls of oil per day, 1,495 Bbls of NGLs per day and 20,779 Mcf of natural gas per day, for total production of 4,975 Boe per day (29,848 Mcfe per day).

Main Pass 108 Field. Main Pass 108 field consists of Main Pass blocks 107, 108 and 109. This field is located off the coast of Louisiana approximately 50 miles east of Venice in 50 feet of water. We acquired our working interests in these blocks, which range from 33% to 100%, in a transaction with Kerr-McGee Oil and Gas Corporation ("Kerr-McGee"). 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, 2012, 43 wells have been drilled in this field, 35 of which were successful. Cumulative field production through 2012 is approximately 41.9 MMBoe gross (251.6 Bcfe gross). One new well reached target depth in 2011 and began production in 2012. In addition, one workover was performed in 2012. During December 2012, production from this field, net to our interest, averaged 329 Bbls of oil per day, 437 Bbls of NGLs per day and 15,246 Mcf of natural gas per day, for total production of 3,306 Boe per day (19,838 Mcfe per day).

Mississippi Canyon 243 Field. (Matterhorn) Mississippi Canyon 243 field is located off the coast of Louisiana, approximately 100 miles southeast of New Orleans, in 2,552 feet of water. The field area covers Mississippi Canyon block 243, with a single floating, tension leg production platform on Mississippi Canyon block 243. Société Nationale Elf Aquitaine discovered the field in 2002. We acquired a 100% working interest in the field from Total E&P USA ("Total E&P") in 2010. Cumulative field production through 2012 is approximately 22.0 MMBoe gross (131.8 Bcfe gross). This field is a supra-salt development with 17 productive horizons at depths ranging to 9,850 feet. As of December 31, 2012, 18 wells have been drilled, eight of which have been successful. During December 2012, production from this field, net to our interest, averaged 2,454 Bbls of oil per day, 282 Bbls of NGLs per day and 3,932 Mcf of natural gas per day, for total production of 3,391 Boe per day (20,347 Mcfe per day).

Viosca Knoll 823 Field. (Virgo) Viosca Knoll 823 field is located off the coast of Louisiana, approximately 125 miles southeast of New Orleans, in 1,014 feet of water. The field area covers Viosca Knoll block 823 and Viosca Knoll block 822, with a single fixed leg production platform on Viosca Knoll block 823. Total E&P discovered the field in 1997. We acquired a 64% working interest in the field from Total E&P in 2010. Cumulative field production through 2012 is approximately 20.0 MMBoe gross (120.5 Bcfe gross). This field is a supra-salt development with 17 productive horizons at depths ranging to 13,335 feet. As of December 31, 2012, 12 wells have been drilled, 10 of which have been successful. During December 2012, production from this field, net to our interest, averaged 292 Bbls of oil per day, 187 Bbls of NGLs per day and 6,182 Mcf of natural gas per day, for total production of 1,510 Boe per day (9,060 Mcfe per day).

High Island 22 Field. High Island 22 field consists of High Island blocks 21 and 22. The field is located approximately 10 miles off the Texas coastline in 36 feet of water. Two platforms, the "A" and the "B", are located on block 22. We acquired a 100% working interest in the field from Kerr-McGee in 2006. The field produces from two major sands, the LH 20 and LH 24. The productive sands are Lower Miocene, Lent Hanseni in age. As of December 31, 2012, 12 wells have been drilled, eight of which have been successful. A recent field study resulted in certain reserves being classified as proved as of December 31, 2012, compared to reserves being classified as unproved in 2011. Cumulative field production through 2012 is approximately 30.0 MMBoe gross (179.9 Bcfe gross). During December 2012, production from this field, net to our interest, averaged one Bbl of oil per day, one Bbl of NGLs per day and 95 Mcf of natural gas per day, for total production of 18 Boe per day (109 Mcfe per day).

Main Pass 98 Field. Main Pass 98 field consists of Main Pass blocks 98 and 180. This field is located off the coast of Louisiana approximately 55 miles east of Venice in 91 feet of water. We acquired our 100% working interest in these blocks from NCX Co LLC in 2009. The field produces from low relief, predominantly stratigraphically trapped sands located between two merging, generally south dipping faults. The productive interval is Middle Miocene Bigenerina Humblei. Cumulative field production through 2012 is approximately 4.1 MMBoe gross (24.7 Bcfe gross). As of December 31, 2012, 11 wells have been drilled, seven of which have been successful. In 2012, no wells were drilled or recompleted and three workovers were performed. During December 2012, production from this field, net to our interest, averaged 106 Bbls of oil per day, 70 Bbls of NGLs per day and 2,171 Mcf of natural gas per day, for total production of 537 Boe per day (3,225 Mcfe 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. These sands are Pleistocene Ang B in age. As of December 31, 2012, 75 wells have been drilled, 57 of which have been successful. Cumulative field production through 2012 is approximately 93.6 MMBoe gross (561.7 Bcfe gross). We own a 100% working interest in the field and are the operator. During December 2012, production from this field, net to our interest, averaged 1,279 Bbls of oil per day and 266 MMcf of natural gas per day, for total production of 1,324 Boe per day (7,942 Mcfe per day).

Proved Reserves

Our estimated proved reserves totaled 117.5 MMBoe (705.1 Bcfe) at December 31, 2012. The mix by product was 47% oil, 13% NGLs and 40% natural gas determined using the energy-equivalent ratio noted below. Our proved reserves were estimated by NSAI, our independent petroleum consultant.

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

	As of December 31, 2012						
				Total Equivalent Reserves			
Classification of Proved Reserves (1)	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Oil Equivalent (MBoe) (2)**	**Natural Gas Equivalent (MMcfe) (2)**	**% of Total Proved**	**PV-10 (3) (In millions)**
Proved developed producing	24,673	8,906	173,906	62,563	375,380	53%	$1,664
Proved developed non-producing	10,663	2,051	69,535	24,303	145,819	21%	777
Total proved developed	35,336	10,957	243,441	86,866	521,199	74%	2,441
Proved undeveloped	19,490	4,220	41,614	30,646	183,874	26%	379
Total proved	54,826	15,177	285,055	117,512	705,073	100%	$2,820

Volume measurements:

MBbls – thousand barrels for crude oil, condensate or NGLs

MBoe – thousand barrels of oil equivalent

MMcf – million cubic feet

MMcfe – million cubic feet equivalent

(1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2012 were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the year end December 31, 2012. Prices were adjusted by lease for quality, transportation, fees, energy content and regional price differentials. For oil, the West Texas Intermediate posted price was used in the calculation and, after adjustments, a price of $98.13 per Bbl was used in computing the amounts above. For NGLs, a ratio was computed for each field of the NGLs realized price compared to the oil realized price. Then, this ratio was applied to the oil price using SEC guidance. The NGLs price of $47.30 per Bbl was used in computing the amounts above. For natural gas, the average Henry Hub spot price was used in the calculation and the adjusted price of $2.77 per Mcf was used in computing the amounts above. Such prices were held constant throughout the estimated lives of the reserves. Future production, development costs and ARO are based on year-end costs with no escalations.

(2) Energy equivalents are determined using the energy-equivalent ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs (totals may not compute due to rounding). The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent price for oil and NGLs may differ significantly.

(3) We refer to PV-10 as the present value of estimated future net revenues of estimated proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs and excludes ARO. We have also included PV-10 after ARO below. PV-10 after ARO includes the present value of ARO related to proved reserves using a 10% discount rate and no inflation of current costs. Neither PV-10 nor PV-10 after ARO are financial measures defined under generally accepted accounting principles ("GAAP"); therefore, the following table reconciles these amounts to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that the non-GAAP financial measures of PV-10 and PV-10 after ARO are relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. PV-10 and PV-10 after ARO are used internally when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. We believe the use of pre-tax measures is valuable because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid. Management believes that the presentation of PV-10 and PV-10 after ARO provide useful information to investors because they are widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. PV-10 and PV-10 after ARO are not measures of financial or operating performance under GAAP, nor are they intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 and PV-10 after ARO should not be considered in isolation or as substitutes for the standardized measure of discounted future net cash flows as defined under GAAP.

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

	As of December 31, 2012
Present value of estimated future net revenues (PV-10)	$2,820
Present value of estimated ARO, discounted at 10%	(328)
PV-10 after ARO	2,492
Future income taxes, discounted at 10%	(646)
Standardized measure of discounted future net cash flows	$1,846

Changes in Proved Reserves

Our total proved reserves increased to 117.5 MMBoe (705.1 Bcfe) at December 31, 2012 from 116.9 MMBoe (701.1 Bcfe) at December 31, 2011, primarily as a result of extensions and discoveries of 15.7 MMBoe (94.5 Bcfe) due to our participation in the drilling of 25 successful exploratory wells (gross) and increases resulting from well completions and recompletions. The extensions and discoveries were primarily in the Yellow Rose Properties (11.6 MMBoe /69.5 Bcfe), the High Island 22 field (2.7 MMBoe/16.2 Bcfe) and the West Cameron 71 field (1.0 MMBoe/6.1 Bcfe). For the Yellow Rose Properties, the increase to proved reserves was due to 11 exploration wells being completed. In addition, there was a redetermination of reserves related to successful horizontal drilling and drilling using 40 acre spacing in certain areas. For the High Island 22 field, the increase in proved reserves was due to a recent field study that demonstrated that additional reserves could be recovered by drilling a replacement for a well that experienced a mechanical failure. The increase at the West Cameron 71 field was due to a successful exploration well. Estimated proved reserves also increased from the acquisition of Newfield Properties discussed in Item 1, *Business*, which added 7.0 MMBoe (42.0 Bcfe). Reserves decreased from revisions of previous estimates by 4.6 MMBoe (27.5 Bcfe) and by 0.4 MMBoe (2.2 Bcfe) from the sale of one field. Decreases due to production were 17.1 MMBoe (102.8 Bcfe). See *Development of Proved Undeveloped Reserves* below for a table reconciling the change in proved undeveloped reserves during 2012. See *Financial Statements – Note 21 – Supplemental Oil and Gas Disclosures under Part II, Item 8 in this Form 10-K* for additional information.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Our estimated proved reserve information as of December 31, 2012 included in this Form 10-K was prepared by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The scope and results of their procedures are summarized in a letter included as an exhibit to this Form 10-K. The primary technical person at NSAI responsible for overseeing the preparation of the reserves estimates presented herein has B.S. and M.S. degrees in Civil Engineering and has been a Registered Professional Engineer in the State of Texas for 24 years and a member of the Society of Petroleum Engineers for over 28 years. He has over 35 years total experience in the oil and gas industry, with over 21 years of reservoir engineering experience. His areas of experience are the continental shelf and deepwater Gulf of Mexico, San Juan Basin, onshore and offshore Mexico, offshore Africa, and unconventional gas sources worldwide. NSAI has informed us that he meets or exceeds the education, training, and experience requirements set forth in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

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

Reserve Technologies

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

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

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

Reporting of Natural Gas and Natural Gas Liquids

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

Development of Proved Undeveloped Reserves

Our proved undeveloped reserves ("PUDs") were estimated by NSAI, our independent petroleum consultant. Future development costs associated with our PUDs at December 31, 2012 were estimated at $583.6 million.

Our PUDs by field as of December 31, 2012 and 2011 are as follows:

	December 31, 2012		December 31, 2011	
	MMBoe	**Bcfe**	**MMBoe**	**Bcfe**
Ship Shoal 349 (Mahogany)	4.8	29.1	16.6	99.8
Mississippi Canyon 243	2.1	12.3	3.1	18.8
Viosca Knoll 823	1.4	8.6	1.4	8.2
Spraberry (Yellow Rose)	19.6	117.7	19.4	116.1
High Island 22	2.7	16.2	—	—
Total	30.6	183.9	40.5	242.9

The following table presents a reconciliation of our PUDs for 2012:

	Year 2012	
	MMBoe	**Bcfe**
Proved undeveloped reserves – beginning of year	40.5	242.9
Reductions:		
Ship Shoal 349 (Mahogany) – three wells drilled, two wells completed, reclassified to proved developed	(11.8)	(70.8)
Mississippi Canyon 243 – one well completed	(1.6)	(9.8)
Spraberry (Yellow Rose) – PUD wells reclassified and performance	(9.7)	(58.0)
Revisions due to pricing	(0.2)	(0.9)
Subtotal – reductions	(23.3)	(139.5)
Balance after reductions	17.2	103.4
Additions:		
High Island 22 – reclassification from unproved due to study	2.7	16.2
Spraberry (Yellow Rose) – PUD well additions	10.0	59.6
Other changes	0.7	4.7
Subtotal – additions	13.4	80.5
Proved undeveloped reserves – end of year	30.6	183.9

Volume measurements:
MMBoe – million barrels of oil equivalent   Bcfe – billion cubic feet equivalent

During 2012, we drilled numerous development wells that converted PUDs to proved developed reserves ("PDs") and spent $263.6 million on development of PUDs during 2012. Activity in 2012 allowed conversion of approximately 50% of the PUDs existing at December 31, 2011 to proved developed reserves as of December 31, 2012. At our Ship Shoal 349/359 (Mahogany) field, we completed two wells, (SS 359 A5 ST and SS 359 A13). As of December 31, 2012, we were in the process of completing the SS 359 A9 ST well, which moved additional reserves from PUDs to PDs. In 2013, we plan to drill the SS 359 A14 well and A15 well. This drilling program has resulted in the reclassification of a substantial portion of the PUDs to PDs in the Mahogany field. The PUDs at our Mississippi Canyon 243 field and Viosca Knoll 823 fields were obtained through acquisitions in 2010. We completed one well at Mississippi Canyon 243 (MC 243 A4 ST) in 2012 and are currently drilling another development well (MC 243 A2 ST BP1). Development of the Mississippi Canyon 243 field and Viosca Knoll 823 field is expected to continue into 2014.

In May 2011, we acquired the Yellow Rose Properties, which contributed to a significant increase in PUDs in 2011. In this field, we completed 27 development wells and nine exploration wells from the acquisition date of May 11, 2011 to December 31, 2011. In 2012, we completed 53 development wells and 11 exploration wells. One of the wells completed was a horizontal well and two other horizontal wells reached target depth in 2012, which proved the concept and allowed additional horizontal PUD locations to be booked. Additionally, wells completed in 2011 and 2012 proved that the concept of down spacing to 40-acres was viable in a portion of the field, allowing the conversion of certain unproven locations to PUDs in 2012. In 2013, we expect to drill approximately 26 development wells and one exploration well, comprised of seven horizontal wells and 20 vertical wells. See *Business* under Part I, Item 1, *Our Fields* in Item 2 above and *Financial Statements – Note 2 – Acquisitions and Divestitures* under Part II, Item 8 in this Form 10-K for additional information on the Yellow Rose Properties.

In the High Island 22 field, a recent field study demonstrated that additional reserves could be recovered by drilling a replacement for a well that experienced a mechanical failure. This allowed unproved reserves in 2011 to be reclassified as proved reserves as of December 31, 2012.

We believe that we will be able to develop all of the reserves classified as PUDs at December 31, 2012 within five years from the date such reserves were recorded. Our capital budget for 2013 is up 6% from our 2012 capital budget, with 37% dedicated to development activities, split 43% offshore and 57% onshore. The capital allocated to our development activities will assist us in converting the PUDs to proved developed reserves.

Acreage

The following summarizes our leasehold at December 31, 2012. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	586,624	356,552	124,137	124,137	710,761	480,689
Deepwater	124,083	65,831	357,120	240,406	481,203	306,237
Total Offshore	710,707	422,383	481,257	364,543	1,191,964	786,926
Onshore	24,978	20,540	196,055	163,824	221,033	184,364
Total	735,685	442,923	677,312	528,367	1,412,997	971,290

Approximately 54% of our total net offshore acreage is developed and approximately 11% of our total net onshore acreage is developed. We have the right to propose future exploration and development projects on the majority of our acreage.

For the offshore undeveloped leasehold, 48,689 net acres of the total 364,543 net undeveloped offshore acres (13%) could expire in 2013, 95,393 net acres (26%) could expire in 2014, 57,166 net acres (16%) could expire in 2015, 31,968 net acres (9%) could expire in 2016, and 131,327 net acres (36%) could expire in 2017 and beyond. For the onshore undeveloped leasehold, our rights to approximately 148,318 net acres of the total 163,824 net undeveloped onshore acres (91%) could expire in 2013, 5,463 net acres (3%) could expire in 2014, 10,038 net acres (6%) could expire in 2015, and five net acres could expire thereafter. Of the undeveloped onshore leasehold, there are 138,235 net acres that can be extended by drilling two additional wells in 2013 and further extended by additional operations or production in future years. In making decisions regarding drilling and operations activity for 2013, we give consideration to undeveloped leasehold that may expire in the near term in order that we might retain the opportunity to extend such acreage.

Our net offshore acreage increased 273,645 net acres (53%) from December 31, 2011 and our net onshore acreage increased 10,930 net acres (6%) from December 31, 2011. The increase in our net offshore acreage was primarily attributable to the Newfield Properties acquisition and offshore property interests acquired through purchase from the government. This increase was partially offset due to certain offshore leases that terminated and the sale of our interest at South Timbalier 41. The increase in our net onshore acreage is primarily attributable to additional leasehold interests acquired in Texas.

Production

For the years 2012, 2011 and 2010, our net daily production averaged 280.9 MMcfe, 278.2 MMcfe and 238.4 MMcfe, respectively. Production increased in 2012 from 2011 primarily due to acquisitions completed in 2012 and 2011 and increases in the Ship Shoal 349 field attributable to development activities, partially offset by decreases related to storms, pipeline shutdowns and natural reservoir declines. Production increased in 2011 from 2010 primarily due to acquisitions completed in 2011 and 2010 and the resumption of operations in certain fields that had been shut down from June 2010 to March 2011 due to pipeline outages.

Production History

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

	Year Ended December 31,		
	2012	2011	2010
Net sales:			
Oil (MBbls)	6,033	6,073	5,863
NGLs (MBbls)	2,129	1,892	1,190
Natural gas (MMcf)	53,825	53,743	44,713
Total oil equivalent (MBoe)	17,133	16,921	14,505
Total natural gas equivalent (MMcfe)	102,800	101,528	87,032

Volume measurements:

MBbls – thousand barrels for crude oil, condensate or NGLs

MBoe – thousand barrels of oil equivalent

MMcf – million cubic feet

MMcfe – million cubic feet equivalent

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

Productive Wells

The following presents our ownership interest at December 31, 2012 in our productive oil and natural gas wells. A net well represents our fractional working interest of a gross well in which we own less than all of the working interest.

Offshore Wells

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	83	72	87	69	170	141
Non-operated	43	18	40	11	83	29
	126	90	127	80	253	170

Onshore Wells

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	174	173	2	2	176	175
Non-operated	9	3	—	—	9	3
	183	176	2	2	185	178

All Productive Wells

	Oil Wells (1)		Gas Wells (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	257	245	89	71	346	316
Non-operated	52	21	40	11	92	32
	309	266	129	82	438	348

(1) Includes seven gross (5.0 net) oil wells and eight gross (4.9 net) gas wells with multiple completions.

Drilling Activity

As presented in the tables below, our drilling activity increased in 2012 compared to 2011, and also increased in 2011 compared to 2010. Our onshore drilling activity increased after our acquisition of the Yellow Rose Properties in May 2011 and additional leasehold interests acquired in both West and East Texas.

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

Development Drilling

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

	Year Ended December 31,		
	2012	2011	2010
Gross Wells:			
Productive:			
Offshore	3	5	1
Onshore	53	27	—
Non-productive:			
Offshore	—	—	—
Onshore	—	—	—
	56	32	1
Net Wells:			
Productive:			
Offshore	3.0	4.5	0.1
Onshore	52.8	27.0	—
Non-productive:			
Offshore	—	—	—
Onshore	—	—	—
	55.8	31.5	0.1

Our success rates related to our gross development wells drilled during 2012, 2011 and 2010 were 100% each year.

Exploration Drilling

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

	Year Ended December 31,		
	2012	2011	2010
Gross Wells:			
Productive:			
Offshore	1	3	5
Onshore	24	12	—
Non-productive:			
Offshore	1	—	1
Onshore	—	1	2
	26	16	8
Net Wells:			
Productive:			
Offshore	0.3	2.4	3.6
Onshore	20.8	7.6	—
Non-productive:			
Offshore	0.4	—	1.0
Onshore	—	0.7	0.7
	21.5	10.7	5.3

Our success rates related to our gross exploration wells drilled during 2012, 2011 and 2010 were 96%, 94% and 63%, respectively.

Recent Drilling Activity

The following table sets forth 2013 drilling activity to February 15, 2013.

	January 1, 2013 to February 15, 2013	
	Development	Exploration
Gross Wells:		
Productive:		
Offshore	—	—
Onshore	8	2
Non-productive:		
Offshore	—	1
Onshore	—	—
	8	3
Net Wells:		
Productive:		
Offshore	—	—
Onshore	8.0	1.9
Non-productive:		
Offshore	—	1.0
Onshore	—	—
	8.0	2.9

As of February 15, 2013, we were in the process of drilling and/or completing on a gross well basis one offshore development well, three offshore exploration wells, nine onshore exploration wells and two onshore development wells.

Capital Expenditures

The level of our investment in oil and gas properties changes from time to time depending on numerous factors, including the prices of oil, NGLs and natural gas, acquisition opportunities and the results of our exploration and development activities. For 2012, our capital expenditures for oil and natural gas properties and equipment of $684.9 million included $205.6 million for acquisitions, $137.1 million for exploration activities, $310.2 million for development activities and $32.0 million for seismic, capitalized interest and other leasehold costs. See *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 of this Form 10-K for additional information.

Item 3. *Legal Proceedings*

Federal Grand Jury Investigation. The United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the EPA conducted a federal grand jury investigation beginning in late 2010 of environmental compliance matters relating to surface discharges and reporting on four of our offshore platforms in the Gulf of Mexico in 2009. In December 2012, an agreement was reached that resolves these environmental violations and the agreement was approved by the federal district court in January 2013. Under the agreement, the Company on January 3, 2013 (i) pled guilty to one felony count under the Clean Water Act for altering monthly produced water discharge samples for the Ewing Banks 910 platform in 2009 and one misdemeanor count under the Clean Water Act for negligently discharging a small amount of oil from the same platform in November 2009 and (ii) paid a $0.7 million fine and $0.3 million for community service and (iii) entered into an environmental compliance program subject to a third-party audit. Under the agreement, the Company was placed on a three-year term of probation. The probation terms require that the Company: a) commit no further criminal violations, b) pay in full amounts pursuant to the agreement, c) comply with an Environmental Compliance Plan during the probation period, and d) take no adverse action against personnel who cooperated in the investigation. The agreement further stipulates that the Government will not seek any further criminal charges against the Company in this matter.

Cameron Parish Louisiana Claim. **Since** 2009, certain Cameron Parish landowners have filed suits in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and Tracy W. Krohn as well as several other defendants unrelated to us. In their lawsuits, plaintiffs alleged that property they own has been contaminated or otherwise damaged by the defendants' oil and gas exploration and production activities and they are seeking compensatory and punitive damages. During 2012, we settled claims with certain landowners and paid $10.0 million. We assessed the remaining claims to be probable and have accrued $1.3 million in our contingent liabilities as of December 31, 2012. However, we cannot state with certainty that our estimates of additional exposure are accurate concerning this matter.

Qui Tam Litigation. On September 21, 2012, we were served with a complaint in a *qui tam* action filed under the federal False Claims Act by an employee of a Company contractor. The lawsuit, *United States ex rel. Comeaux v. W&T Offshore, Inc., et al.; CA No. 10-494*, was filed in the United States District Court for the Eastern District of Louisiana, against the Company and three other working interest owners related to claims associated with three of the Company's operated production platforms. A *qui tam* action, also known as a "whistleblower" action, is a lawsuit brought by a private citizen seeking civil penalties or damages against a person or company on behalf of the government for alleged violations of law. If the claims are successful, the person filing the suit may recover a percentage of the damages or penalty from the lawsuit as a reward for exposing a wrongdoing and recovering funds on behalf of the government. The complaint was originally filed in 2010 but kept under confidential seal in order for the federal government to decide if it wished to intervene and take over the prosecution of the *qui tam action*. The government declined to intervene in this suit and the complaint was unsealed and made public in June 2012, thereby giving the plaintiff the opportunity to pursue the claims on behalf of the government.

The complaint alleges that environmental violations at three of our operated production platforms in the Gulf of Mexico violate the federal offshore lease provisions so that we, among other things, wrongfully retained benefits under the applicable leases. The alleged environmental violations include allegations of discharges of relatively small amounts of oil into the Gulf of Mexico, the failure to report and record such discharges, and falsification of certain produced water samples and related reports required under federal law. The events are alleged to have occurred in 2009. These are largely the same allegations involved in the federal grand jury investigation described above. We have filed a motion to dismiss the claim. The plaintiff dismissed his claims against the three other working interest owners after they filed motions to dismiss. The plaintiff conceded that certain of his claims should be dismissed in his reply to the Company's motion to dismiss. The motion remains pending before the court.

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

Insurance Claims. During the fourth quarter of 2012, underwriters of our excess liability policies (Indemnity Insurance Company of North America, New York Marine & General Insurance Company, Navigators Insurance Company; XL Specialty Insurance Company and Liberty Mutual Insurance Co.) filed declaratory judgment actions in the United States District Court for the Southern District of Texas seeking a determination that such policies do not cover removal of wreck and debris claims arising from Hurricane Ike that occurred in 2008. The court consolidated the various suits filed by underwriters. We have not yet filed any claim under such excess policies, but we anticipate that such claims may reach $50.0 million in aggregate. In January 2013, the Company filed a motion for summary judgment seeking the court's determination that such excess policies do in fact provide coverage for such removal of wreck and debris claims. The motion for summary judgment is pending. If successful, we expect to receive reimbursement for these costs once costs have been incurred and claims submitted. Costs that have been incurred in connection with potential claims have been recorded in *Oil and natural gas properties and equipment* on the Consolidated Balance Sheet. Any recoveries from claims made on these policies related to this issue will be recorded as reductions in this line item.

Proceedings by Government Authorities. During 2012, we received notices of non-compliance from various government authorities that were related to various incidences occurring in 2012 and in prior years. Excluding the $1.0 million in payments described above, cumulative payments of fines during 2012 were less than $0.1 million. There are currently no fines outstanding that have not been paid and management has not been informed of any potential fines relating to recently completed inspections at this time.

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

Executive Officers of the Registrant

The following lists our executive officers:

Name	Age (1)	Position
Tracy W. Krohn	58	Founder, Chairman, Director and Chief Executive Officer
Jamie L. Vazquez	52	President
John D. Gibbons	59	Senior Vice President, Chief Financial Officer and Chief Accounting Officer
Thomas P. Murphy	50	Senior Vice President and Chief Operations Officer
Stephen L. Schroeder	50	Senior Vice President and Chief Technical Officer
Thomas F. Getten	65	Vice President, General Counsel and Corporate Secretary

(1) Ages as of February 23, 2013.

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

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

John D. Gibbons joined the Company in February 2007 as Senior Vice President and Chief Financial Officer. 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.

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

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

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

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

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

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

	High	Low
2012		
First Quarter	$26.83	$20.24
Second Quarter	21.56	13.31
Third Quarter	21.01	14.72
Fourth Quarter	19.35	15.54
2011		
First Quarter	26.12	17.51
Second Quarter	28.79	21.09
Third Quarter	29.27	13.74
Fourth Quarter	22.86	11.87

As of February 25, 2013, there were 198 registered holders of our common stock.

Dividends

Under the Credit Agreement, we are allowed to pay annual dividends up to $60.0 million per year if we are not in default. In December 2012, we were granted a one-time waiver which allowed for cash dividends of up to $85.0 million during 2012. In addition, the indenture governing our 8.50% Senior Notes due in 2019 (the "8.50% Senior Notes") contains restrictions on the payment of dividends unless we meet certain restricted payment tests. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* under Part II, Item 7 and *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for more information regarding our Credit Agreement and the indenture governing the 8.50% Senior 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	Dividends per Share of Common Stock
2012		
First Quarter	$ 5,948	$0.08
Second Quarter	5,950	0.08
Third Quarter	5,950	0.08
Fourth Quarter (1)	64,984	0.87
2011		
First Quarter	2,979	0.04
Second Quarter	2,979	0.04
Third Quarter	2,979	0.04
Fourth Quarter (2)	49,819	0.67

(1) Includes a regular dividend of $6.0 million ($0.08 per common share) and two special cash dividends of $34.9 million ($0.47 per common share) and $24.1 million ($0.32 per common share).

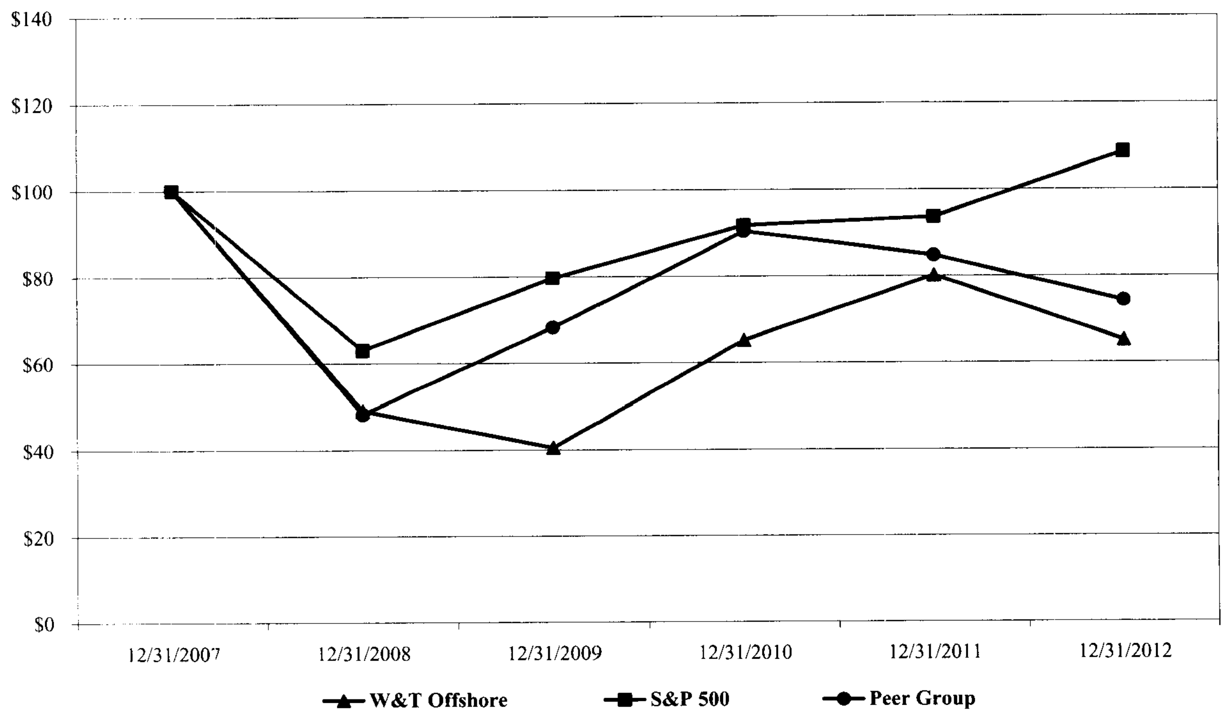
(2) Includes a regular dividend of $3.0 million ($0.04 per common share) and a special cash dividend of $46.9 million ($0.63 per common share).

With the exception of 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 directors and applicable debt agreement restrictions. On February 26, 2013, our board of directors declared a cash dividend of $0.08 per common share, payable on March 29, 2013 to shareholders of record on March 15, 2013.

Stock Performance Graph

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

WTI vs. S&P 500 / Peer Averages



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

Securities Authorized for Issuance Under Equity Compensation Plans

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

Issuer Purchases of Equity Securities

For the year 2012, we did not purchase any of our equity securities.

The following table sets forth information about restricted stock units delivered by employees during the quarter ended December 31, 2012 to satisfy tax withholding obligations on the vesting of restricted stock units.

Period	Total Number of Restricted Stock Units Delivered	Average Price per Restricted Stock Unit	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2012 – October 31, 2012	N/A	N/A	N/A	N/A
November 1, 2012 – November 30, 2012	N/A	N/A	N/A	N/A
December 1, 2012 – December 31, 2012	319,403	$16.68	N/A	N/A

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

SELECTED HISTORICAL FINANCIAL INFORMATION

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

	Year Ended December 31,				
	2012 (1)	2011 (2)	2010 (3)	2009	2008
	(Dollars in thousands, except per share data)				
Consolidated Statement of Income (Loss) Information:					
Revenues:					
Oil	$629,548	$643,222	$453,435	$ 365,411	$ 622,388
NGLs	84,637	105,559	51,931	35,247	65,709
Natural gas	158,390	221,194	203,533	204,758	527,352
Other (4)	1,916	1,072	(3,116)	5,580	160
Total revenues (5)	874,491	971,047	705,783	610,996	1,215,609
Operating costs and expenses:					
Lease operating expenses (6)	232,260	219,206	169,670	203,922	229,747
Production taxes	5,840	4,275	1,194	1,544	8,827
Gathering and transportation	14,878	16,920	16,484	13,619	15,957
Depreciation, depletion and amortization	336,177	299,015	268,415	308,076	482,464
Asset retirement obligation accretion	20,055	29,771	25,685	34,461	39,312
Impairment of oil and natural gas properties (7)	—	—	—	218,871	1,182,758
General and administrative expenses	82,017	74,296	53,290	42,990	47,225
Derivative (gain) loss	13,954	(1,896)	4,256	7,372	16,464
Total costs and expenses	705,181	641,587	538,994	830,855	2,022,754
Operating income (loss)	169,310	329,460	166,789	(219,859)	(807,145)
Interest expense, net of amounts capitalized	49,994	42,516	37,706	40,087	34,709
Loss on extinguishment of debt (8)	—	22,694	—	2,926	—
Other income (9)	215	84	710	842	13,372
Income (loss) before income tax expense (benefit)	119,531	264,334	129,793	(262,030)	(828,482)
Income tax expense (benefit)	47,547	91,517	11,901	(74,111)	(269,663)
Net income (loss)	$ 71,984	$172,817	$117,892	$(187,919)	$ (558,819)
Earnings (loss) per common share					
Basic and diluted	$ 0.95	$ 2.29	$ 1.58	$ (2.51)	$ (7.36)
Dividends on common stock (10)	82,832	58,756	59,609	9,158	27,713
Cash dividends per common share (10)	1.11	0.79	0.80	0.12	0.36
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$385,137	$521,478	$464,772	$ 156,266	$ 882,496
Capital expenditures – oil and natural gas properties	684,863	719,026	415,653	276,134	774,879

	December 31,				
	2012	2011	2010	2009	2008
	(Dollars in thousands)				
Consolidated Balance Sheet Information:					
Cash and cash equivalents	$ 12,245	$ 4,512	$ 28,655	$ 38,187	$ 357,552
Total assets	2,348,987	1,868,925	1,424,094	1,326,833	2,056,186
Long-term debt	1,087,611	717,000	450,000	450,000	653,172
Shareholders' equity	541,187	544,574	421,743	358,950	572,227

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

(2) In the second quarter of 2011, we acquired the Yellow Rose Properties from Opal and, in the third quarter of 2011, we acquired the Fairway Properties from Shell.

(3) In the second quarter of 2010, we acquired certain properties from Total E&P and, in the fourth quarter of 2010, we acquired certain properties from Shell.

(4) Included in other revenues for 2010 is a reduction of $4.7 million due to a disallowance by the ONRR of royalty relief for transportation of deepwater production through our subsea pipeline system that was originally recorded in 2009. We are contesting this ONRR adjustment.

(5) Included in total revenues for 2010 is $24.9 million related to the recoupment of royalties paid to the ONRR in prior periods based on price thresholds that were believed to limit the availability of royalty relief on certain properties subject to the OCS Deepwater Relief Act of 1995.

(6) Included in lease operating expenses are net charges to expense for hurricane-related repairs netted with insurance reimbursements. For the years 2010, 2009 and 2008, the impact to lease operating expenses attributable to net hurricane – related expenses/reimbursements were $11.7 million decrease, $18.4 million increase and $17.7 million increase, respectively. There was minimal impact to lease operating expenses in the other years presented.

(7) The carrying amount of our oil and natural gas properties was written down by $218.9 million in 2009 and $1.2 billion in 2008 through the application of the full cost ceiling limitation due to lower oil and natural gas prices. No such write downs were required during the other years presented.

(8) In 2011, we expensed repurchase premiums, deferred financing costs and other costs totaling $22.0 million related to the repurchase of $450.0 million in aggregate principal amount of our 8.25% Senior Notes due 2014 (the "8.25% Senior Notes") and expensed $0.7 million of deferred financing costs related to replacement of our revolving bank credit facility. In 2009, we expensed $2.9 million of deferred financing costs related to the early repayment of our previously outstanding term loan facility ("Tranche B").

(9) In 2012, other income consisted primarily of gain from the sale of interest in an airplane. Amounts reported in all other periods presented consisted primarily of interest income.

(10) The years 2012, 2011, 2010, and 2008 included special dividends of $59.0 million ($0.79 per share), $46.9 million ($0.63 per share), $49.2 million ($0.66 per share), and $20.8 million ($0.39 per share), respectively. The year 2009 did not include a special dividend.

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 proved reserves have been made in accordance with the rules and regulations of the SEC in effect for that time period. For additional information regarding our estimated proved reserves, please read *Business* under Part I, Item 1 and *Properties* under Part I, Item 2 of the Form 10-K. The selected historical operating data set forth below should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 and with *Financial Statements* under Part II, Item 8 in this Form 10-K.

	December 31,				
	2012	**2011**	**2010**	**2009**	**2008**
Reserve Data:					
Estimated net proved reserves (1)(2):					
Oil (MMBbls)	54.8	51.4	34.0	31.2	40.0
NGLs (MMBbls)	15.2	17.1	4.2	3.0	3.9
Natural gas (Bcf)	285.1	289.7	256.3	165.8	227.9
Total oil equivalent (MMBoe)	117.5	116.9	80.9	61.8	81.9
Total natural gas equivalent (Bcfe)	705.1	701.1	485.4	371.0	491.1
Proved developed producing (Bcfe)	375.4	325.8	236.6	162.5	148.6
Proved developed non-producing (Bcfe) (3)	145.8	132.4	154.7	121.0	185.5
Total proved developed (Bcfe)	521.2	458.2	391.3	283.5	334.1
Proved undeveloped (Bcfe)	183.9	242.9	94.1	87.5	157.0
Total proved developed reserves as % of proved reserves	73.9%	65.4%	80.6%	76.4%	68.0%
Reserve additions (reductions) (Bcfe):					
Revisions (4)	(27.5)	51.1	20.2	(25.4)	(157.5)
Extensions and discoveries	94.5	32.0	29.2	23.4	47.2
Purchases of minerals in place	42.0	234.1	152.0	0.7	60.5
Sales of minerals in place	(2.2)	—	—	(24.0)	—
Production	(102.8)	(101.5)	(87.0)	(94.8)	(97.9)
Net reserve additions (reductions)	4.0	215.7	114.4	(120.1)	(147.7)

(1) Estimated net proved reserves as of December 31, 2012, 2011, 2010 and 2009 are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December of the respective year in accordance with SEC guidelines. Estimated reserves as of December 31, 2008 are based on end-of-period commodity prices in accordance with the previous SEC guidelines in effect on such dates.

(2) Energy equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs (totals may not compute due to rounding). The energy-equivalent ratio does not assume price equivalency, and the energy equivalent prices for oil, NGLs and natural gas may differ significantly.

(3) Approximately 29.6 Bcfe of reserves were shut-in at December 31, 2010 due to two pipeline outages impacting several fields, including our Main Pass 108 field. 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.

(4) Revisions for 2009 included decreases attributable to the changes in reserve reporting requirements for oil and natural gas companies enacted by the SEC, which became effective for us on December 31, 2009. The revised 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.

Volume measurements:

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

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Operating Data:					
Net sales:					
Oil (MBbls)	6,033	6,073	5,863	6,095	5,886
NGLs (MBbls)	2,129	1,892	1,190	1,103	1,084
Oil and NGLs (MBbls)	8,163	7,964	7,053	7,198	6,970
Natural gas (MMcf)	53,825	53,743	44,713	51,621	56,072
Total oil equivalent (MBoe)	17,133	16,921	14,505	15,801	16,315
Total natural gas equivalent (MMcfe)	102,800	101,528	87,032	94,806	97,892
Average daily equivalent sales (Boe/day)	46,813	46,360	39,741	43,290	44,577
Average daily equivalent sales (Mcfe/day)	280,875	278,158	238,445	259,741	267,465
Average realized sales prices (Unhedged):					
Oil ($/Bbl)	$ 104.35	$ 105.92	$ 77.33	$ 59.96	$ 105.74
NGLs ($/Bbl)	39.75	55.81	43.65	31.96	60.62
Oil and NGLs ($/Bbl)	87.50	94.02	71.65	55.67	98.72
Natural gas ($/Mcf)	2.94	4.12	4.55	3.97	9.40
Oil equivalent ($/Boe)	50.93	57.32	48.87	38.32	74.50
Natural gas equivalent ($/Mcfe)	8.49	9.55	8.15	6.39	12.42
Average realized sales prices (Hedged) (1):					
Oil ($/Bbl)	103.08	$ 104.30	$ 77.05	$ 59.96	$ 100.94
NGLs ($/Bbl)	39.75	55.81	43.65	31.96	60.62
Oil and NGLs ($/Bbl)	86.56	92.78	71.42	55.67	94.67
Natural gas ($/Mcf)	2.94	4.12	4.71	3.96	9.42
Oil equivalent ($/Boe)	50.48	56.74	49.25	38.30	72.82
Natural gas equivalent ($/Mcfe)	8.41	9.46	8.21	6.38	12.14
Average per Mcfe ($/Mcfe):					
Lease operating expenses	$ 2.26	$ 2.16	$ 1.95	$ 2.15	$ 2.35
Gathering and transportation costs	0.14	0.17	0.19	0.14	0.16
Production costs	2.40	2.33	2.14	2.29	2.51
Production taxes	0.06	0.04	0.01	0.02	0.09
Depreciation, depletion, amortization and accretion	3.47	3.24	3.38	3.61	5.33
General and administrative expenses	0.80	0.73	0.61	0.45	0.48
	$ 6.73	$ 6.34	$ 6.14	$ 6.37	$ 8.41
Total number of wells drilled (gross):					
Offshore	5	8	7	13	25
Onshore	77	40	2	—	—
Total number of productive wells drilled (gross):					
Offshore	4	8	6	10	19
Onshore	77	39	—	—	—

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

Volume measurements:

Bbl – barrel

Boe – barrel of oil equivalent

MBbls – thousand barrels for crude oil, condensate or NGLs

MBoe – thousand barrels of oil equivalent

Mcf – thousand cubic feet

MMcf – million cubic feet

MMcfe – million cubic feet equivalent

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

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

Overview

We are an independent oil and natural gas producer focused primarily in the Gulf of Mexico and Texas. We have grown through exploration, development and acquisitions and currently hold working interests in approximately 72 offshore fields (69 producing and three capable of producing) in federal and state waters. During 2011, we expanded onshore into West Texas and East Texas through an acquisition and acquiring interests in leasehold acreage. We have interests in offshore leases covering approximately 1.2 million gross acres (0.8 million net acres) spanning primarily across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama and 0.2 million gross acres (0.2 million net acres) onshore substantially all in Texas. We operate wells accounting for approximately 84% of our average daily production. We own interests in approximately 211 offshore structures, 144 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 increasing production and reserves at a profit. We strive to grow our reserves and production through acquisitions and our drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to continue to add reserves post-acquisition.

In October 2012, we acquired from Newfield certain oil and gas leasehold interests. The properties consisted of leases covering 78 federal offshore blocks on approximately 432,700 gross acres (416,000 gross acres and 268,000 net acres excluding over-riding interests), comprised of 65 blocks in the deepwater, six of which are producing, 10 blocks on the conventional shelf, four of which are producing, and an overriding royalty interest in three deepwater blocks, two of which are producing. Internal estimates of proved reserves associated with the Newfield Properties as of the acquisition date were approximately 7.0 MMBoe (42.0 Bcfe), comprised of approximately 61% natural gas, 36% oil and 3% NGLs, all of which were classified as proved developed. Including adjustments from an effective date of July 1, 2012, the adjusted purchase price was $205.6 million and we assumed the ARO associated with the Newfield Properties, which we have estimated to be $31.7 million. The acquisition was initially funded from borrowings under our revolving bank credit facility and cash on hand. Subsequently in the same month, the amounts borrowed under our revolving bank credit facility were paid down with funds provided from the issuance of an additional $300.0 million of 8.50% Senior Notes.

During 2011, we closed two acquisition transactions. In May 2011, we acquired from Opal approximately 24,500 gross acres (21,900 net acres) of certain oil and gas leasehold interests in the Permian Basin of West Texas, which we refer to as our Yellow Rose Properties. Internal estimates of proved reserves associated with the Yellow Rose Properties as of the acquisition date were approximately 30.1 MMBoe (180.4 Bcfe), comprised of approximately 69% oil, 22% NGLs and 9% natural gas, and approximately 70% of which were classified as proved undeveloped. Including adjustments from an effective date of January 1, 2011, the adjusted purchase price was $394.4 million, and we assumed the ARO associated with the Yellow Rose Properties, which we have estimated to be $0.4 million, and recorded a long-term liability of $2.1 million. The acquisition was funded from cash on hand and borrowings under our revolving bank credit facility.

In August 2011, we acquired from Shell its 64.3% interest in the Fairway Field along with a like interest in the associated Yellowhammer gas treatment plant. Internal estimates of proved reserves associated with the Fairway Properties as of the acquisition date were 8.9 MMBoe (53.5 Bcfe), comprised of approximately 72% natural gas, 27% NGLs and less than 1% oil, all of which are proved developed producing. Including adjustments from an effective date of September 1, 2010, the adjusted purchase price was $42.9 million and we assumed the ARO associated with the Fairway Properties, which we have estimated to be $7.8 million. The acquisition was funded from borrowings under our revolving bank credit facility.

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

From time to time, as part of our business strategy, we sell various properties that we consider non-core assets. In 2012, we sold our 40%, non-operated working interest in the South Timbalier 41 field located in the Gulf of Mexico for $30.5 million. In connection with this sale, we reversed $4.0 million of ARO. In 2011 and 2010, there were no property sales of significance.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for 2012 were comprised of approximately 35% oil and condensate, 12% NGLs and 52% natural gas, determined using the energy-equivalent ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs. The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices per Mcfe for oil, NGLs and natural gas may differ significantly. For 2012, our combined total production of oil, NGLs and natural gas was approximately 1.3% higher on a Mcfe basis than during the same period in 2011.

During 2012, sales volumes were negatively impacted by Hurricane Isaac, Tropical Storm Debbie and various pipeline outages. Our estimate of the impact of these items on 2012 volumes was approximately 0.8 MMBoe (4.8 Bcfe).

During 2012, our average realized oil sales price (unhedged) decreased to $104.35 per barrel compared to $105.92 per barrel in 2011. Two comparable benchmarks are the unweighted average daily posted spot price of West Texas Intermediate ("WTI") crude oil and the unweighted average daily posted spot price of Brent crude oil, which decreased 0.9% and increased 0.3%, respectively, from 2011. WTI is frequently used to value domestically produced crude oil, and the majority of our oil production is priced using the spot price for WTI as a base price plus a premium depending on the type of crude oil. Most of our oil production is from our offshore operations and is comprised of various crudes including Heavy Louisiana Sweet, Light Louisiana Sweet, Poseidon and others. Starting in the first quarter of 2011 and continuing through the fourth quarter of 2012, these various crudes sold at a significant premium relative to WTI. During 2012, premiums for Heavy Louisiana Sweet crude and Light Louisiana Sweet crude ranged between $10.00 and $22.00 per barrel. For the month of December 2012, the average premium for these crudes was between $21.00 and $22.00 per barrel. In comparison, the premium for these crudes was between $4.00 and $30.00 per barrel for 2011. In 2010, the premium was approximately $2.00 to $3.00 per barrel, which is representative of the historical norm. We may continue to experience higher premiums to WTI crude in our future sales of crude oil until such time as the causative factors, described below, are resolved. We cannot predict with any certainty how long such pricing conditions will last.

A possible cause cited by industry publications for the premiums afforded our offshore crudes is an oversupply situation at Cushing, Oklahoma, a primary domestic hub for crude oil priced using the WTI benchmark. Citing the Cushing crude over supply situation, the owners of the Seaway pipeline reversed the flow of crude oil in June 2012 to flow crude from Cushing to Freeport, Texas. Although this change increased the amount of crude oil available to Gulf Coast refineries, we did not experience a decline in premiums in the second half of 2012. In January 2013, the Seaway pipeline capacity was increased from 150,000 barrels per day to 400,000 barrels per day. The owners have announced plans to construct a parallel pipeline to be completed in the first quarter of 2014, which is expected to increase the capacity to 850,000 barrels per day. Other pipeline projects are underway as well that, when added to the Seaway pipeline capacity, could bring 1.9 million barrels per day of mid-continent crude oil to the Gulf Coast. That capacity is expected to grow to 2.4 million barrels per day by the end of 2014. We believe these actions may substantially reduce the oversupply situation at Cushing, which may affect the premiums we receive on our offshore oil production. An additional factor that has appeared to affect the premiums for Heavy Louisiana Sweet and Light Louisiana Sweet is the difference between the Brent and WTI crude oil prices, which continue to have a higher spread than historical norms. When the price of Brent crude increases relative to WTI, the value of low-sulfur U.S. crude grades that compete with West African crude increases. This trend of higher Brent spreads began in the first quarter of 2011 and continued through December 2012.

Oil prices are affected by world events, such as political unrest in the Middle East, the threat of hostilities, demand changes in various countries and world economic growth. Some commentators believe world economic growth, which is currently being affected by the economies of China, Brazil, India and Russia, may support strong crude oil prices in the long term.

Not-withstanding this long-term view, crude oil prices will likely continue to be volatile. For 2012, WTI crude oil prices ranged from a high of approximately $109.00 per barrel to a low of $78.00 per barrel. The volatility in price was attributed by some commentators to be due in part to the debt crisis in Europe and the belief that economic growth in certain world markets was weakening. The U.S. Energy Information Administration ("EIA") expects the oil market to loosen in the near term as supply increases are expected to be higher than consumption increases. EIA expects inventories to build in the first half of 2013. Supply increases are expected from the United States and other Non-OPEC countries. Consumption increases are expected in China and other countries outside of the Organization for Economic Cooperation and Development. EIA projections do not assume any significant deterioration of the economies of the United States and European Union. EIA projects crude prices for Brent and WTI will be lower in 2013 compared to 2012. Estimates of global oil demand by EIA for 2012 and 2013 were 89.0 and 90.0 million barrels per day, respectively, which would be approximately 1% growth year over year.

Our average realized NGLs sales prices (unhedged) decreased 28.8% during 2012 compared to 2011. According to industry sources, domestic NGLs production significantly increased over 2011 levels which affected price realizations. During 2012, prices for domestic ethane and propane, two common NGL components, decreased 52% and 31%, respectively, from 2011 and other domestic NGLs prices decreased 8% to 12%. As long as ethane and propane inventories continue to be high and NGLs production continues to increase, we could expect prices for these two commodities to be weak. In addition, as long as the crude to natural gas price ratio remains wide, NGLs production may continue to be high, which may put downward pressure on the entire NGLs stream. In addition, many natural gas processing facilities are re-injecting ethane back into the natural gas stream after processing due to increasing ethane supplies. This in turn increases natural gas supplies and has helped to lead to lower natural gas pricing.

Natural gas prices are more affected by domestic issues (as compared to crude oil prices), such as weather (particularly extreme heat or cold), supply, local demand issues and domestic economic conditions, and they have historically been subject to substantial fluctuation. During 2012, the average realized sales price for our natural gas production decreased 28.6% from 2011 to $2.94 per Mcf. A comparable bench mark is the Henry Hub unweighted average daily posted spot price, which decreased 31.3% from the comparable period. We expect continued weakness in natural gas prices for a number of reasons, including (i) producers continuing to drill in order to secure and to hold large lease positions before expiration, particularly in shale and similar resource plays, (ii) natural gas storage levels building to high levels throughout the injection season, (iii) natural gas continuing to be produced as a by-product in conjunction with the substantial ramp up of oil drilling, (iv) increasing availability of liquefied natural gas, (v) production efficiency gains are achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling and production techniques and (vi) re-injecting ethane into the natural gas stream as indicated above which increases the natural gas supply. EIA estimates that natural gas consumption in 2012 increased 4.8% from 2011 to 69.7 billion cubic feet per day due to gains in electrical power use offsetting declines in residential and commercial consumption and expects 2013 consumption to decline slightly from 2012 levels. The EIA expects production growth to increase slightly in 2013 as the associated gas with crude oil drilling will offset the declines in natural gas drilling. According to

Baker Hughes, the natural gas rig count at the end of 2012 is down approximately 50% compared with the start of 2012. EIA expects the Henry Hub natural gas price will average $3.79 per Mcf in 2013 compared to an estimated $2.86 per Mcf in 2012. Due to the high production and historically high inventory levels, we believe natural gas prices may continue to be weak until such time as crude prices weaken (which will in turn decrease oil drilling activity and decrease the likelihood of producing natural gas as a byproduct), economic activity increases dramatically or fuel switching increases. During 2012, U.S. energy producers switched from coal-powered energy to natural gas, estimated by the EIA at approximated 4 Bcfe per day, particularly during the summer cooling season. Industry sources have indicated that a price above $3.50 per Mcf will probably cause power producers to switch back to coal from natural gas, which in effect creates limits to how far natural gas prices can rise until such time as demand for natural gas increases from other sources.

In 2012, 2011 and 2010, we did not incur an impairment write-down. Should prices decline for oil, NGLs and natural gas in the future, our future oil, NGL and natural gas revenues, earnings and liquidity would be negatively impacted, and could result in impairment write-downs of the carrying value of our oil and natural gas properties. This decline could create issues with financial ratio compliance, and could result in a reduction of the borrowing base associated with our credit agreement, depending on the severity of such declines. If those factors were to occur and were significant, the willingness of financial institutions and investors to provide capital to us and others in the oil and natural gas industry in the future could be impacted.

Our operating costs include the expense of operating our wells, platforms and other infrastructure primarily in the Gulf of Mexico and Texas and transporting our production 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.

Revenue from our production is highly dependent on pipelines owned by others to access markets for our products. To the extent that the transportation rate such pipelines charge increases, our revenues from the sales of our products would go down or transportation costs would increase, the result of either would be a reduction in operating income. We have reached agreements with certain gas pipelines that significantly reduce the rates we are charged relative to their most recent filed tariff rates, but still represent an increase from prior rates that will negatively impact our operating income. For other third-party pipelines that handle our product, the potential transportation rate changes and timing are not known at this time. The approval process typically results in approval of fees less than those contained in the filing requests. The combined impact cannot be specifically determined, as the impact is dependent on volumes, the amount of transportation rate change for certain pipeline operators and the timing of such changes. However, we estimate that the combined detrimental impact to operating income in excess of the impact experienced in 2012 for these pipelines' price changes may be up as much as $10.0 million for 2013.

In recent years, we acquired and built platforms near the outer edge of the continental shelf and operated 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.

Our operations are exposed to potential damage from hurricanes and we obtain insurance to reduce our financial exposure risk. We incurred substantial costs from 2008 through 2012 for hurricane related damage occurring in 2008 and expect to incur costs through 2013 to complete plugging and abandonment work primarily related to three toppled platforms. We received reimbursements from our insurance carrier in each of the last four years and expect to receive additional reimbursements for covered costs incurred in future periods as covered costs incurred to date have not exceeded policy limits. See *Liquidity and Capital Resources* below and *Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims* under Part II, Item 8 in this Form 10-K for additional information.

Applicable environmental regulations require us to remove our platforms after production has ceased, to plug and abandon all wells and to remediate any environmental damage our operations may have caused. The costs associated with our ARO generally increase as we drill wells in deeper parts of the continental shelf and in the deepwater. We generally do not pre-fund our ARO. We estimated the present value of our liability related to our ARO at $384.1 million as of December 31, 2012. Inherent in the present value calculation of our liability are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and expenditure, and changes in the legal, regulatory, environmental and political environments. Actual expenditures for ARO could vary significantly from these estimates.

In April 2010, there was a fire and explosion aboard the Deepwater Horizon drilling platform operated by BP in the deep water of the Gulf of Mexico which caused loss of life, caused the rig to sink and created a major oil spill that produced economic, environmental and natural resource damage. Subsequently, the BOEM issued a series of NTLs and other significant changes in regulations and implemented a six-month moratorium on drilling activities which began in May 2010. After the drilling moratorium ended in November 2010, it was not until March 2011 that deep water drilling permits began to be issued, and even then only sporadically, to continue drilling activities that had commenced prior to the Deepwater Horizon incident. Since March 2011, deepwater drilling permits have been issued, albeit at a slower and much more measured pace than before the Deepwater Horizon event. The most significant regulatory changes since the Deepwater Horizon event are regulations related to assessing the potential environmental impact of future spills using worse case discharge scenarios on a well-by-well basis, spill response documentation, compliance reviews, operator practices related to safety and implementing a safety and environmental management system. The new regulations and increased review process increases the time it takes to obtain drilling permits and increases the cost of operations. As these new regulations and guidance continue to evolve, we cannot estimate the cost and impact to our business at this time. The permitting process is also slow and inconsistent for shallow water work and even for plug and abandonment activities. This could lead to increased costs and performing work at less than optimal effectiveness or even at less than desirable times due to weather. We have not experienced delays in obtaining permits related to our onshore operations.

Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Revenues. Total revenues decreased $96.6 million, or 9.9%, to $874.5 million in 2012 compared to 2011. Oil revenues decreased $13.7 million, NGLs revenues decreased $20.9 million, natural gas revenues decreased $62.8 million and other revenues increased $0.9 million. The oil revenue decrease was attributable to a 1.5% decrease in the average realized sales price (unhedged) to $104.35 per Bbl in 2012 from $105.92 per Bbl in 2011, with sales volumes decreasing slightly. The NGLs revenue decrease was attributable to a 28.8% decrease in the average realized sales price (unhedged) to $39.75 per Bbl in 2012 from $55.81 per Bbl in 2011, partially offset by an increase of 12.5% in sales volumes. The natural gas revenue decrease was attributable to a 28.6% decrease in the average realized natural gas sales price (unhedged) to $2.94 per Mcf from $4.12 per Mcf for 2011, with sales volumes increasing slightly. The sales volumes for all commodities were negatively impacted by Hurricane Isaac, Tropical Storm Debbie, various pipeline outages, and natural production declines, and were positively impacted by acquisitions and successful exploration and development efforts.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, maintenance on our facilities, and hurricane remediation costs net of insurance claims, increased $13.1 million to $232.3 million in 2012 compared to 2011. On a per Mcfe basis, lease operating expenses increased to $2.26 per Mcfe during 2012 compared to $2.16 per Mcfe during 2011. On a component basis, base lease operating expenses, workover costs, insurance premiums and hurricane remediation costs net of insurance claims increased $7.4 million, $6.8 million, $2.9 million and $0.9 million, respectively. As a partial offset, facility expenses decreased $4.9 million. The increase in base lease operating expenses is primarily attributable to acquisitions in 2012 and 2011. Workover cost increases were primarily attributable to increases for our onshore operations, which had approximately four months of expenses in 2011. The increase in insurance premiums is attributable to increases effective with the June 1, 2011 renewal, which included an expansion in coverage and led to higher expenses in the first half of 2012. The decrease in facilities expense is primarily attributable to work performed in 2011 on the tendon tension monitoring system and mechanical repairs at our Matterhorn platform, the pipeline repairs at our Ship Shoal 300 field to remove paraffin and inspection fees at our Main Pass 252 platforms. These projects were only partially offset by other projects in 2012.

Production taxes. Production taxes increased to $5.8 million during 2012 compared to $4.3 million in 2011 primarily due to the Yellow Rose Properties and the Fairway Properties' operations and are currently not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes while onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased to $14.9 million in 2012 from $16.9 million in 2011 due to a higher percentage of onshore volumes, where transportation fees are lower.

Depreciation, depletion, amortization and accretion ("DD&A"). DD&A, including accretion for ARO, increased to $3.47 per Mcfe for 2012 from $3.24 per Mcfe for 2011. On a nominal basis, DD&A increased to $356.2 million for 2012 from $328.8 million in 2011. The increase in DD&A on a per Mcfe and nominal basis was due in part to costs capitalized to the full cost pool from both the unevaluated pool and from increases in our ARO estimates without a corresponding increase in proved reserves. In addition, we incurred significant development capital throughout the year that did not lead to an increase in proved reserves. Finally, most of our reserve additions for 2012 occurred late in the year.

General and administrative expenses ("G&A"). G&A increased to $82.0 million for 2012 from $74.3 million for 2011. Included in 2012 is $13.9 million that relates to the settlement of environmental claims made by certain landowners in Cameron Parish, Louisiana, the settlement with the Department of Justice of an environmental enforcement claim and associated legal costs. These costs exceeded similar amounts incurred in 2011 by $9.5 million. In addition, the overhead that we bill out to our joint interest parties was higher in the 2012 period by $1.9 million primarily due to a full year of operations at our Fairway Properties and increased drilling activities. The 2011 period included higher payments for transition services associated with the acquisitions completed in that year. On a per Mcfe basis, G&A was $0.80 per Mcfe for 2012, compared to $0.73 per Mcfe for 2011. See *Financial Statements – Note 11 – Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 of this Form 10-K for additional information.

Derivative (gain) loss. For 2012 and 2011, we recognized a loss of $14.0 million and a gain of $1.9 million, respectively, related to the change in the fair value of our crude oil commodity derivatives as a result of changes in crude oil prices relative to the prices at the beginning of the period. Although the contracts relate to production for both the current and future years, changes in the fair value for all open contracts are recorded currently. For 2012, the loss was comprised of a $7.7 million realized loss and a $6.3 million unrealized loss. For 2011, the gain was comprised of a $9.9 million realized loss and an $11.8 million unrealized gain. See *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K for additional information.

Interest expense. Interest expense incurred increased to $63.3 million for 2012 from $52.4 million for 2011 with the increase primarily attributable to the issuance of Senior Notes. The average amount of our Senior Notes outstanding increased due to our June 2011 issuance of $600.0 million of our 8.50% Senior Notes and repurchase of $450.0 million of our 8.25% Senior Notes. In addition, we issued an additional $300.0 million of 8.50% Senior Notes in October 2012. During 2012 and 2011, interest of $13.3 million and $9.9 million, respectively, were capitalized to unevaluated oil and natural gas properties. The increase is primarily attributable to the acquisition of the Yellow Rose Properties in 2011. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information.

Loss on extinguishment of debt. In 2012, no loss on extinguishment of debt was incurred. For 2011, loss on extinguishment of debt was $22.7 million. In 2011, we expensed repurchase premiums, deferred financing costs and other costs totaling $22.0 million related to the repurchase of $450.0 million in aggregate principal amount of our 8.25% Senior Notes due 2014 and expensed $0.7 million of deferred financing costs related to replacement of our revolving bank credit facility. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information.

Income tax expense. Income tax expense decreased to $47.5 million for 2012 compared to $91.5 million for 2011. Our effective tax rate for 2012 was 39.8% and differed from the federal statutory rate of 35% primarily as a result of the recapture of deductions for qualified domestic production activities under Section 199 of the Internal Revenue Code ("IRC") as a function of loss carrybacks to prior years and the impact of state income taxes. Our effective tax rate for 2011 was 34.6% and differed from the federal statutory rate of 35% primarily as a result of the deduction for qualified domestic production activities under Section 199 of the IRC.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Revenues. Total revenues increased $265.3 million, or 37.6%, to $971.0 million in 2011 compared to 2010. Oil revenues increased $189.8 million, NGLs revenues increased $53.6 million, natural gas revenues increased $17.7 million and other revenues increased $4.2 million. The oil revenue increase was attributable to a 37.0% increase in the average realized sales price (unhedged) to $105.92 per Bbl in 2011 from $77.33 per Bbl in 2010, combined with an increase of 3.4% in sales volumes. The NGLs revenue increase was attributable to a 27.9% increase in the average realized sales price (unhedged) to $55.81 per Bbl in 2011 from $43.65 per Bbl in 2010, combined with an increase of 58.3% in sales volumes. The sales volume increase for oil and NGLs is primarily attributable to increases associated with properties acquired in 2011 and 2010. The natural gas revenue increase resulted from a 20.1% increase in sales volumes, partially offset by a 9.5% decrease in the average realized natural gas sales price (unhedged) to $4.12 per Mcf compared to $4.55 per Mcf for 2010. The sales volume increase for natural gas is primarily attributable to increases associated with our acquisition activities, the Main Pass 108 fields resuming production and successful exploration efforts. Other revenue changed primarily due to a disallowance of $4.7 million by the ONRR in 2010 of royalty relief for transportation of deepwater production through our subsea pipeline system. We are contesting this ONRR adjustment. For additional information, see *Financial Statements – Note 19 – Contingencies* under Part II, Item 8 of this Form 10-K.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, maintenance on our facilities, and hurricane remediation costs net of insurance claims, increased $49.5 million to $219.2 million in 2011 compared to 2010. On a per Mcfe basis, lease operating expenses increased to $2.16 per Mcfe during 2011 compared to $1.95 per Mcfe during 2010. On a component basis, base lease operating expenses, facility expenses, hurricane remediation costs net of insurance claims, and workover costs increased $20.7 million, $14.1 million, $11.7 million and $3.6 million, respectively. As a partial offset, insurance premiums decreased $0.6 million. The increase in base lease operating expenses is primarily attributable to expenses associated with the properties acquired in 2011 and 2010, higher costs at our various non-operated properties and increased processing fees associated with our Daniel Boone field production. The increase in facility expenses is primarily attributable to work performed on the tendon tension monitoring system and mechanical repairs at our Matterhorn platform, the pipeline repairs at our Ship Shoal 300 field to remove paraffin and inspection fees at our Main Pass 252 platforms. Hurricane remediation costs net of insurance claims increased primarily due to higher reimbursements received in 2010. Workover costs increased due to work performed at our Yellow Rose Properties and expenses at the Main Pass 108 field, partially offset by projects in 2010 that did not occur in 2011. The decrease in insurance premiums resulted primarily from lower premiums on our insurance policies covering well control and hurricane damage that cover the policy period June 1, 2010 to

June 1, 2011. Our premiums increased effective with the June 1, 2011 renewal attributable to a substantial improvement in coverage. For additional information, see *Liquidity and Capital Resources – Hurricane Remediation and Insurance Claims.*

Production taxes. Production taxes increased to $4.3 million during 2011 compared to $1.2 million in 2010 primarily due to the Yellow Rose Properties and the Fairway Properties' operations and are currently not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes while onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs were basically flat for 2011 compared to the prior year.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $3.24 per Mcfe for 2011 from $3.38 per Mcfe for 2010. On a nominal basis, DD&A increased to $328.8 million for 2011 from $294.1 million in 2010. The decrease in DD&A on a per Mcfe basis was primarily due to increases in proved reserves while DD&A on a nominal basis increased due to higher production volumes.

General and administrative expenses. G&A increased to $74.3 million for 2011 from $53.3 million for 2010 due to a number of factors including higher incentive compensation as a result of improved financial and operational performance, costs related to expanded onshore and offshore activities, acquisitions, surety premiums, transition services fees paid to the sellers of the acquired properties, and litigation related costs. Also, we earned administration fees in 2010 related to an asset disposition, and no such fees were earned in 2011. On a per Mcfe basis, G&A was $0.73 per Mcfe for 2011, compared to $0.61 per Mcfe for 2010. See *Financial Statements – Note 11 – Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 of this Form 10-K for additional information.

Derivative (gain) loss. For 2011 and 2010, we recognized a gain of $1.9 million and a loss of $4.3 million, respectively, related primarily to the change in the fair value of our crude oil commodity derivatives as a result of changes in crude oil prices relative to the prices at the beginning of the period. Although the contracts relate to production for both the current and future years, changes in the fair value for all open contracts are recorded currently. For 2011, the gain was comprised of a $9.9 million realized loss and an $11.8 million unrealized gain. For 2010, the loss was comprised of a $0.8 million realized gain and a $5.1 million unrealized gain. Included in 2010 was a derivative loss of $0.3 million related to our interest rate swap. See *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K for additional information.

Interest expense. Interest expense incurred increased to $52.4 million for 2011 from $43.1 million for 2010, with the increase primarily attributable to our Senior Notes. The average amount of our Senior Notes outstanding increased due to our June 2011 issuance of $600.0 million of our 8.50% Senior Notes and repurchase of $450.0 million of our 8.25% Senior Notes. During 2011 and 2010, $9.9 million and $5.4 million, respectively, of interest were capitalized to unevaluated oil and natural gas properties which increased due to the Yellow Rose Properties acquisition. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information.

Loss on extinguishment of debt. For 2011, loss on extinguishment of debt was $22.7 million. In 2011, we expensed repurchase premiums, deferred financing costs and other costs totaling $22.0 million related to the repurchase of $450.0 million in aggregate principal amount of our 8.25% Senior Notes due 2014 and expensed $0.7 million of deferred financing costs related to replacement of our revolving bank credit facility. In 2010, no loss on extinguishment of debt was incurred. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information.

Income tax expense. Income tax expense increased to $91.5 million for 2011 compared to $11.9 million for 2010. Our effective tax rate for 2011 was 34.6% and differed from the federal statutory rate of 35% primarily as a result of the deduction for qualified domestic production activities under Section 199 of the IRC. Our effective tax rate for 2010 was 9.2% and primarily reflects a reduction in our valuation allowance against our deferred tax assets and the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the IRC. Taxable income in 2010 allowed us to reverse all of our previously recorded valuation allowance.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures and strategic property acquisitions to allow us to grow our oil and natural gas reserves, repay outstanding borrowings and make related interest payments and pay dividends. We have funded such activities with cash on hand, cash provided by operating activities, 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 2012 was $385.1 million, compared to $521.5 million for 2011. The decrease is primarily attributable to lower realized prices for natural gas and NGLs, higher payments related to ARO and increases in joint interest receivables. Partially offsetting the decrease were lower payments related to income taxes of $16.1 million in 2012 compared to $35.7 million in 2011, and higher production volumes. Our combined average realized sales price per Mcfe (hedged) during 2012 was 11.1% lower than the comparable 2011 period, while our combined production of oil, NGLs and natural gas on a natural gas equivalent basis during 2012 was 1.3% higher than 2011.

Net cash used in investing activities during 2012 and 2011 was $657.4 million and $722.7 million, respectively, which primarily represents our investments in oil and natural gas properties. Cash used in investing activities for 2012 includes the acquisition of the Newfield Properties for $205.6 million. Cash used in investing activities for 2011 includes the acquisitions of the Yellow Rose Properties for $394.4 million and the Fairway Properties for $42.9 million. In addition, investments in other oil and natural gas properties and equipment were $479.3 million in 2012 compared to $281.8 million in 2011, with the increase primarily related to drilling activities onshore and in deepwater offshore areas.

Net cash provided by financing activities was $280.0 million during 2012. Funds were provided through the issuance of an additional $300.0 million of 8.50% Senior Notes at a premium of 106% to par, which after netting debt issuance costs, provided $312.0 million. In addition, $53.0 million was provided through net borrowings on our revolving bank credit facility. Funds used were primarily attributable to the payment of dividends of $82.8 million, which includes two special dividends totaling $59.0 million. Net cash provided by financing activities was $177.1 million during 2011. Funds were provided through net borrowings on the revolving bank credit facility of $117.0 million and issuance of $600.0 million of 8.50% Senior Notes and partially offset by the repurchase of $450.0 million of the 8.25% Senior Notes and repurchase premium and debt issuance costs of $32.3 million. In addition, dividend payments were $58.8 million in 2011, which included a special dividend of $46.9 million. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information on the Senior Note transactions.

At December 31, 2012, we had a cash balance of $12.2 million and $554.4 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $725.0 million as of December 31, 2012.

Credit agreement and long-term debt. At December 31, 2012, $170.0 million was outstanding under our revolving bank credit facility compared to $117.0 million at December 31, 2011. At December 31, 2012 and 2011, $900.0 million and $600.0 million principal amount, respectively, of our 8.50% Senior Notes were outstanding. We believe that cash provided by operations, borrowings available under our revolving bank credit facility and other external sources of liquidity should be sufficient to fund our ongoing cash requirements.

On May 7, 2012, we executed the First Amendment to the Fourth Amended and Restated Credit Agreement (the "First Amendment"), which, among other things, increased the number of participating lenders and added a provision permitting the Company to maintain security interest in favor of any derivative counterparties that cease to be lenders under the Company's revolving bank credit facility. On October 12, 2012, we executed the Second Amendment to the Fourth Amended and Restated Credit Agreement (the "Second Amendment"), which, among other things, allowed for the issuance of additional senior unsecured indebtedness with an automatically and simultaneously reduction in the borrowing base by $0.25 for every $1.00 of unsecured indebtedness incurred above $600.0 million aggregate principal amount of our existing notes until such time as the borrowing base has been determined or otherwise adjusted. All other terms of the Credit Agreement remain substantially the same prior to the First and Second Amendment including the termination date of May 5, 2015, interest rate spreads and covenants. Fees related to the First and Second Amendments were approximately $2.5 million, which are being amortized over the remaining term of the Credit Agreement.

Effective on November 7, 2012, our borrowing base was increased to $725.0 million and the number of lenders increased. We currently have 20 lenders within the revolving bank credit facility, with commitments ranging from $20.0 million to $56.0 million for the current borrowing base. While we have not experienced, nor do we anticipate, any difficulties in obtaining funding from any of these lenders at this time, any lack of or delay in funding by members of our banking group could negatively impact our liquidity position.

Availability under our revolving bank credit facility is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the size of our revolving bank credit facility. Borrowings under the revolving bank credit facility bear interest at the applicable London Interbank Offered Rate or LIBOR, plus applicable margins ranging from 2.00% to 2.75%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, and (c) LIBOR plus 1%, plus applicable margins ranging from 1.00% to 1.75%. The unused portion of the borrowing base is subject to a commitment fee of 0.50%.

The Credit Agreement contains covenants that limit, among other things, the payment of cash dividends in excess of $60.0 million per year, common stock repurchases and Senior Note repurchases in excess of $100.0 million in the aggregate, borrowings other than from the revolving bank credit facility, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. In December 2012, we were granted a one-time waiver which allowed for cash dividends of up to $85.0 million during 2012. The Credit Agreement contains various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2012.

During 2012, the outstanding borrowings on the revolving bank credit facility reached a high of $330.0 million primarily to fund the acquisition of the Newfield Properties. These borrowings were reduced to $170.0 million as of December 31, 2012. Letters of credit outstanding as of December 31, 2012 were $0.6 million.

On October 24, 2012, we issued an additional $300.0 million of 8.50% Senior Notes at a premium of 106% par value with an interest rate of 8.50% and maturity date of June 15, 2019, which have identical terms to the Senior Notes issued in June 2011. The proceeds were used to pay down amounts outstanding on the revolving bank credit facility. The 8.50% Senior Notes mature on June 15, 2019 and interest is payable semi-annually in arrears on June 15 and December 15 of each year. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information about our Credit Agreement and long-term debt. We were in compliance with all applicable covenants related to the 8.50% Senior Notes as of December 31, 2012.

In January 2012, holders of the $600.0 million 8.50% Senior Notes issued in June 2011 exchanged their Senior Notes for registered notes with the same terms. In February 2013, holders of the $300.0 million 8.50% Senior Notes issued in October 2012 exchanged their Senior Notes for registered notes with the same terms.

From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of December 31, 2012, our outstanding derivative instruments consisted of commodity swap oil contracts relating to approximately 1.3 MMBbls and 0.7 MMBbls of our anticipated oil production for 2013 and 2104, respectively. During January and February of 2013, we have entered into additional derivative contracts for oil related to our anticipated 2013 and 2014 production. See *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K for additional information about our derivatives.

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

Through December 31, 2012, we have received cash from our insurance carrier related to Hurricane Ike claims totaling $142.2 million and have no insurance receivables recorded as of December 31, 2012 for claims that have been submitted and approved for payment. As of December 31, 2012, we have recorded in ARO an estimate of $6.6 million for additional costs to be incurred related to Hurricane Ike and we have estimated that this work will be completed by the end of 2013. We expect to receive reimbursement for a portion of these costs once costs are incurred and claims submitted. In addition, we have incurred removal of wreck costs related to Hurricane Ike, but some of our insurance carriers are disputing whether such costs are covered costs; therefore, we cannot estimate the amount of reimbursement to be received at this time. Should necessary expenditures exceed our insurance coverage for damages incurred as a result of Hurricane Ike, or claims are denied or there are significant delays in recovering further claims for other reasons, we expect that our available cash on hand, cash flow from operations and the availability under our revolving bank credit facility will be sufficient to meet these future cash needs.

During the fourth quarter of 2012, underwriters of W&T's excess liability policies (Indemnity Insurance Company of North America, New York Marine & General Insurance Company, Navigators Insurance Company; XL Specialty Insurance Company and Liberty Mutual Insurance Co.) filed declaratory judgment actions in the United States District Court for the Southern District of Texas seeking a determination that such policies do not cover removal of wreck and debris claims arising from Hurricane Ike that occurred in 2008. The court consolidated the various suits filed by underwriters. W&T has not yet filed any claim under such excess policies, but W&T anticipates that such claims may reach $50.0 million in aggregate. In January 2013, the Company filed a motion for summary judgment seeking the court's determination that such excess policies do in fact provide coverage for such removal of wreck and debris claims. The motion for summary judgment is pending. If successful, we expect to receive reimbursement for these costs once costs have been incurred and claims submitted. We have incurred $45.6 million to date and expect to incur an additional $5.0 million in costs related to removal of wreck associated with platforms damaged by Hurricane Ike. Removal-of-wreck costs are recorded in *Oil and natural gas properties and equipment* on the Consolidated Balance Sheet. Any recoveries from claims made on these policies related to this issue will be recorded as reductions in this line item, which will reduce our DD&A rate and replenish our cash expenditures.

For a discussion of our hurricane remediation costs related to lease operating expenses incurred during 2012, 2011 and 2010, refer to *Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims* under Part II, Item 8 of this Form 10-K. We expect that the majority of insurance reimbursements subsequent to December 31, 2012 will be attributable to plugging and abandonment activities. Insurance reimbursements related to plugging and abandonment activities are recorded as reductions to *Oil and natural gas properties* on the Consolidated Balance Sheet, which would affect future DD&A expense.

We currently carry three layers of insurance coverage for our operating activities in the Gulf of Mexico. The current policy limits for well control and hurricane damage (defined as named windstorm in our policies) are up to $100.0 million and $140.0 million, respectively, and the policies are effective until June 1, 2013. We carry an additional $100.0 million of well control coverage effective until June 1, 2013 on certain wells at our Mahogany, Matterhorn, Virgo, Main Pass 107/108, Tahoe and SE Tahoe fields. A retention amount of $5.0 million for well control events and $40.5 million per hurricane occurrence must be satisfied by us before we are indemnified for losses. Pollution causing a negative environmental impact is characterized as a covered component of each of the well control and hurricane sections of the policy.

We estimate that as of December 31, 2012, approximately 91% of the estimated future net revenues discounted at 10% (PV-10) attributable to our Gulf of Mexico properties are on platforms that are covered under our current insurance policies for named windstorm damage. The percentage of our PV-10 value fields that are covered are less than last year due to the acquisition of the Newfield Properties. Since we closed on the Newfield Properties near the end of named windstorm season and much of the property value is in subsea wells, we elected not to purchase named windstorm insurance on the assets. There are certain other properties we have deemed as non-core and do not cover for named windstorm damage.

Our general and excess liability policy is effective until May 1, 2013 and provides for $250.0 million of liability coverage for bodily injury and property damage, including liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility requirement under the Ocean Pollution Act, we are required to evidence $150.0 million of financial responsibility to the BSEE. We qualify to self-insure for $35.0 million of this amount and the remaining $115.0 million is covered by insurance.

The premiums for the above policies were $30.6 million for the May/June 2012 policy renewals compared to $32.3 million for the expiring policies. The decrease in our premiums effective with the June 1, 2012 renewal was primarily attributable to an improved insurance market, likely due to less windstorm activity. We do not carry business interruption insurance.

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

	Year Ended December 31,		
	2012	**2011**	**2010**
		(in thousands)	
Acquisition of Newfield Properties	$205,550	$ —	$ —
Acquisition of Yellow Rose Properties	—	394,377	—
Acquisition of Fairway Properties	—	42,870	—
Acquisition of (adjustments to) Tahoe Properties	—	(5,700)	121,933
Acquisition of properties from Total E&P	—	—	115,012
Exploration (1)	137,055	77,606	60,164
Development (1)	310,205	179,705	77,230
Seismic, capitalized interest, other leasehold costs	32,053	30,168	41,314
Acquisitions and investments in oil and gas property/equipment	$684,863	$719,026	$415,653

(1) Reported geographically in the subsequent table.

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

	Year Ended December 31,		
	2012	2011	2010
		(in thousands)	
Conventional shelf	$104,401	$132,680	$115,503
Deepwater	65,856	4,826	9,358
Deep shelf	11,961	5,833	3,382
Onshore	265,042	113,972	9,151
Exploration and development capital expenditures	$447,260	$257,311	$137,394

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

	Completed			Non-commercial		
	2012	2011	2010	2012	2011	2010
Offshore – gross wells drilled:						
Conventional shelf	3	7	6	1	—	1
Deep shelf	1	1	—	—	—	—
Wells operated by W&T	3	7	3	n/a	n/a	n/a
Onshore:						
Gross wells drilled	77	39	—	—	1	2
Wells operated by W&T	73	33	—	n/a	n/a	n/a

As of December 31, 2012, we were in the process of drilling and/or completing nine onshore development wells in Texas, six onshore exploration wells in Texas, two offshore exploration wells and one offshore development well.

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

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

In 2012, we acquired 11 leases from the BOEM for $2.5 million. In 2011, we did not participate in bidding for any Gulf of Mexico leases on the OCS. Due to the government mandated moratorium that began in April 2010, Gulf of Mexico lease sales conducted by the U.S. government through the BOEM were suspended until December 2011. Leases acquired from the BOEM in the March 2010 lease sale totaled five leases for $8.7 million.

From time to time, we sell various oil and gas properties for a variety of reasons including, change of focus, perception of value and to reduce debt, among other reasons. In 2012, we sold our 40% non-operated working interest in the South Timbalier 41 field located in the Gulf of Mexico for $30.5 million and reduced ARO by $4.0 million. In 2011 and 2010, there were no property sales of significance.

Our total capital expenditure budget for 2013 currently is $450.0 million, not including any potential acquisitions. The budget includes 63% for exploration and 37% for development and these percentages include amounts for facilities capital, recompletions, seismic and leasehold items. Geographically, the budget includes 63% for offshore (11 wells) and 37% for onshore. The budget for offshore includes two deepwater wells and a joint interest arrangement in another deepwater well, of which we are not the operator. The budget for onshore includes 27 wells in the Yellow Rose Properties and amounts currently designated for our Terry County and East Texas prospects for completion work and additional wells, which require further evaluation. Our 2013 capital budget is subject to change as conditions warrant and we strive to be as flexible as possible.

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

Dividends. In 2012, we paid \$82.8 million in dividends, which included two special dividends totaling \$59.0 million and regular dividends of \$23.8 million. In 2011, we paid \$58.8 million in dividends, which included a special dividend of \$46.9 million and regular dividends of \$11.9 million. In 2010, we paid \$59.6 million in dividends, which included a special dividend of \$49.2 million and regular dividends of \$10.4 million. Future special dividends cannot be predicted and are subject to approval of the board of directors, which will consider the performance of the Company, its financial condition, future investment opportunities and other factors as our majority shareholder and the board of directors deems appropriate.

Capital Markets and Impact on Liquidity. During 2012 and 2011, we accessed the capital markets for our 8.50% Senior Notes and renewed our revolving bank credit facility arrangement in 2011 as described above. In 2012 and 2011, the U.S. financial markets were not adversely affected by the events in the international markets, including the financial crisis that has threatened the various countries in the Euro zone. Such crisis had an impact on European banks that had exposure to these countries which could ultimately impact borrowers in the United States. Currently, the Euro zone financial markets appear to have stabilized, but the underlying cause of certain countries' high debt levels may take years to reduce their risk profile. The longer-term outlook could be impacted from these or other international events. At this time, we do not have current plans to obtain additional financing in 2013, but this situation could change depending on a number of factors, such as acquisition opportunities and prices of oil and natural gas.

A fairly recent example of scarce financing availability occurred in 2009 when the global financial markets and economic conditions were severely distressed. There were concerns of bank failures and liquidity concerns whether our banks would be able to meet their commitments under credit arrangements in place during that time. In addition, prices for oil and natural gas had decreased from 2008. These conditions contributed to fewer financing transactions being completed.

Asset retirement obligations. Each year (or more often if conditions warrant) we review, and to the extent necessary, revise our ARO estimates. Our ARO at December 31, 2012 and 2011 were \$384.1 million and \$393.9 million, respectively. In 2012, we revised our estimate to account for the increased cost to comply with new regulations including an increase in work scope and interpretation of work scope. See *Financial Statements – Note 5 – Asset Retirement Obligations* under Part II, Item 8 of this 10-K for additional information regarding our estimation of our ARO.

Contractual obligations. The following table summarizes our significant contractual obligations by maturity as of December 31, 2012. At December 31, 2012, we did not have any capital leases.

	Payments Due by Period at December 31, 2012				
	Total	**Less Than One Year**	**One to Three Years**	**Three to Five Years**	**More Than Five Years**
	(Dollars in millions)				
Long-term debt – principal	\$1,070.0	\$ —	\$170.0	\$ —	\$ 900.0
Long-term debt – interest (1)	512.6	84.4	163.8	153.0	111.4
Drilling rigs	36.5	36.5	—	—	—
Operating leases	13.1	1.2	2.6	2.6	6.7
Asset retirement obligations	384.1	92.6	97.9	48.3	145.3
Derivatives (2)	9.4	9.4	—	—	—
Other liabilities (3)	5.5	—	5.5	—	—
	\$2,031.2	\$224.1	\$439.8	\$203.9	\$1,163.4

(1) Interest on long-term debt is comprised of: (a) interest on our 8.50% Senior Notes, which bear interest at a fixed rate of 8.50% and (b) interest on our revolving bank credit facility, which has a variable interest rate, estimated using the borrowings outstanding as of December 31, 2012, an annual interest rate of 3.0%, which was the interest rate as of December 31, 2012, and the commitment fee of 0.5% on the unused balance as of December 31, 2012. Interest was calculated through the stated maturity date of the related debt.
(2) The amounts for the derivative contracts reported above are the unrealized fair values liability as of December 31, 2012. Actual payments at the settlement date could vary significantly from these amounts.
(3) We have excluded security requirements pursuant to the Purchase and Sale agreement with Total E&P for the ARO on certain properties as we plan to utilize bonds, not cash, to fulfill the requirements. Further, if cash were to be deposited in escrow, the funds would be returned when the plugging and abandonment work has been completed. A similar rationale was applied to exclude the potential additional security requirements pursuant to the Purchase and Sale agreement with Shell. See *Financial Statements – Note 16 – Commitments* under Part II, Item 8 of this 10-K for additional information.

Inflation and Seasonality

Inflation. For 2012, our realized prices (unhedged) for oil decreased 1.5%, NGLs decreased 28.8% and natural gas decreased 28.6% from 2011. These are discussed in the *Overview* section above. Costs measured on a $/Mcfe basis increased by 6.2% in 2012 compared to 2011. The cost per Mcfe is impacted by factors other than cost changes, such as work activity including workovers, production levels and insurance reimbursements. Historically, costs for goods and services have moved directionally with the price of oil, NGLs and natural gas, as these commodities affect the demand for these goods and services. In recent years, other factors have influenced the cost of goods and services. For example, in 2009, some offshore third-party contractors were in high demand associated with remediation work related to Hurricane Ike which increased the price for these types of contractors. In 2010, prices for offshore third-party contractors were relatively stable as drilling activity was curtailed due to the moratorium, but boat prices and other services escalated due to contract work for BP in connection with the cleanup effort from the oil spill at the Macondo well. Other costs, such as insurance premiums, have fluctuated with changes in hurricane activity, the oil spill at the BP Macondo well and other factors besides production volumes. More recently, many commodity prices, including oil, copper, steel and other types of metals, have fluctuated wildly with various world events. Some of this fluctuation is due to strong economic activity in certain parts of the world while other changes appear to be driven by political events around the world, the weak US dollar and other foreign currencies. Also, inflation is impacted as a result of record federal deficits and expectations that large deficits will continue.

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

Critical Accounting Policies

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

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

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

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

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

Impairment of oil and natural gas properties. Under the full cost method of accounting, we are required to periodically perform a "ceiling test," which determines a limit on the book value of our oil and natural gas properties. Any write downs occurring as a result of the ceiling test impairment are not recoverable or reversible in future periods. We did not have a ceiling test impairment in 2012, 2011 or 2010, but we did have ceiling test impairments in 2009 and in 2008 as a result of the significant decline in both oil and natural gas prices that began in the second half of 2008. Declines in oil and natural gas prices after December 31, 2012 may require us to record additional ceiling test impairments in the future.

Oil and natural gas reserve quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of DD&A and impairment assessment of our oil and natural gas properties. We make changes to DD&A rates and impairment calculations in the same period that changes to our reserve estimates are made. Our proved reserve information as of December 31, 2012 included in this Form 10-K was estimated by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The accuracy of our reserve estimates is a function of:

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

Insurance receivables. We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection, which arises when our insurance underwriters' adjuster reviews and approves such costs for payment by the underwriters. Actual collections may be significantly different than these estimates and revisions could impact our lease operating expense, our oil and natural gas property balance and our DD&A rates.

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

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

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

Income taxes. We provide for income taxes in accordance with 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 recording tax assets and liabilities. We record adjustments to reflect actual taxes paid in the period we complete our tax returns. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

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

Share-based compensation. 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. We estimate forfeitures during the service period and make adjustments depending on actual experience. These adjustments can create timing differences on when expense is recognized.

Accounting Policies and Pronouncements

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. We have utilized derivative contracts to reduce the risk of fluctuations in commodity prices and expect to use these instruments in the future. We are currently a party to derivative contracts for oil.

Commodity price risk. Our revenues, profitability and future rate of growth substantially depend upon market prices for oil, NGLs and natural gas, which fluctuate widely. Oil, NGLs and natural gas price declines and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. For example, assuming a 10% decline in our average realized oil, NGLs and natural gas sales prices in 2012, our income before income taxes would have decreased by approximately 71% in 2012. If costs and expenses of operating our properties had increased by 10% in 2012, our income before income taxes would have decreased by 21% in 2012.

As of December 31, 2012, we had derivative contracts for oil with a notional quantity of 2.0 MMBbls and various termination dates in 2013 and 2014. We do not designate our commodity derivative contracts as hedging instruments. While these derivative contracts are intended to reduce the effects of volatile oil prices, they may also limit future income from favorable price movements. For additional details about our derivative contracts, refer to *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K.

Interest rate risk. As of December 31, 2012, we had $170.0 million outstanding on our revolving bank credit facility and during 2012 we had amounts outstanding that ranged from zero to $330.0 million. The revolving bank credit facility has a variable interest rate which is primarily impacted by the rates for the LIBOR and the margin ranges from 2.0% to 2.75% depending on the amount outstanding. In 2012, if interest rates would have been 100 basis points higher (an additional 1%); our interest expense would have been approximately $1.0 million higher. We did not have any derivative contracts related to interest rates as of December 31, 2012.

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

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the 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, 2012 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, 2012 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited W&T Offshore, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2012, 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, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2012 and 2011, and the related consolidated statements of income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012 of W&T Offshore, Inc. and subsidiaries and our report dated February 27, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2012 and 2011, and the related consolidated statements of income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), W&T Offshore, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2013, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 27, 2013

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 12,245	$ 4,512
Receivables:		
Oil and natural gas sales	97,733	98,550
Joint interest and other	56,439	25,804
Income tax receivable	47,884	—
Total receivables	202,056	124,354
Deferred income taxes	267	2,007
Prepaid expenses and other assets	25,555	30,315
Total current assets	240,123	161,188
Property and equipment – at cost:		
Oil and natural gas properties and equipment (full cost method, of which $123,503 at December 31, 2012 and $154,516 at December 31, 2011 were excluded from amortization)	6,694,510	5,959,016
Furniture, fixtures and other	21,786	19,500
Total property and equipment	6,716,296	5,978,516
Less accumulated depreciation, depletion and amortization	4,655,841	4,320,410
Net property and equipment	2,060,455	1,658,106
Restricted deposits for asset retirement obligations	28,466	33,462
Other assets	19,943	16,169
Total assets	$2,348,987	$1,868,925
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 123,885	$ 75,871
Undistributed oil and natural gas proceeds	37,073	33,732
Asset retirement obligations	92,630	138,185
Accrued liabilities	20,755	29,705
Income taxes payable	266	10,392
Total current liabilities	274,609	287,885
Long-term debt, less current maturities	1,087,611	717,000
Asset retirement obligations, less current portion	291,423	255,695
Deferred income taxes	145,249	58,881
Other liabilities	8,908	4,890
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value, 20,000,000 shares authorized and 0 issued at December 31, 2012 and $0.00001 par value, 2,000,000 shares authorized and 0 issued at December 31, 2011	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 78,118,803 issued and 75,249,630 outstanding at December 31, 2012; 77,220,706 issued and 74,351,533 outstanding at December 31, 2011;	1	1
Additional paid-in capital	396,186	386,920
Retained earnings	169,167	181,820
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	541,187	544,574
Total liabilities and shareholders' equity	$2,348,987	$1,868,925

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2012	2011	2010
	(In thousands, except per share data)		
Revenues	$874,491	$971,047	$705,783
Operating costs and expenses:			
Lease operating expenses	232,260	219,206	169,670
Production taxes	5,840	4,275	1,194
Gathering and transportation	14,878	16,920	16,484
Depreciation, depletion and amortization	336,177	299,015	268,415
Asset retirement obligation accretion	20,055	29,771	25,685
General and administrative expenses	82,017	74,296	53,290
Derivative (gain) loss	13,954	(1,896)	4,256
Total costs and expenses	705,181	641,587	538,994
Operating income	169,310	329,460	166,789
Interest expense:			
Incurred	63,268	52,393	43,101
Capitalized	(13,274)	(9,877)	(5,395)
Loss on extinguishment of debt	—	22,694	—
Other income	215	84	710
Income before income tax expense	119,531	264,334	129,793
Income tax expense	47,547	91,517	11,901
Net income	$ 71,984	$172,817	$117,892
Basic and diluted earnings per common share	$ 0.95	$ 2.29	$ 1.58
Weighted average common shares outstanding	74,354	74,033	73,685

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock Outstanding		Additional Paid-In Capital	Retained Earnings	Treasury Stock		Total Shareholders' Equity
	Shares	Value			Shares	Value	
				(In thousands)			
Balances at December 31, 2009	74,711	$ 1	$373,050	$ 10,066	2,869	$(24,167)	$358,950
Cash dividends:							
Common stock regular ($0.14 per share)	—	—	—	(10,446)	—	—	(10,446)
Common stock special ($0.66 per share)	—	—	—	(49,132)	—	—	(49,132)
Share-based compensation	—	—	5,533	—	—	—	5,533
Restricted stock issued, net of forfeitures	(95)	—	1,357	—	—	—	1,357
Shares surrendered for payroll taxes	(142)	—	(2,411)	—	—	—	(2,411)
Net income	—	—	—	117,892	—	—	117,892
Balances at December 31, 2010	74,474	$ 1	$377,529	$ 68,380	2,869	$(24,167)	$421,743
Cash dividends:							
Common stock regular ($0.16 per share)	—	—	—	(11,913)	—	—	(11,913)
Common stock special ($0.63 per share)	—	—	—	(46,842)	—	—	(46,842)
Share-based compensation	—	—	9,710	—	—	—	9,710
Restricted stock issued, net of forfeitures	(13)	—	—	—	—	—	—
Shares surrendered for payroll taxes	(109)	—	(2,073)	—	—	—	(2,073)
Other	—	—	1,754	(622)	—	—	1,132
Net income	—	—	—	172,817	—	—	172,817
Balances at December 31, 2011	74,352	$ 1	$386,920	$181,820	2,869	$(24,167)	$544,574
Cash dividends:							
Common stock regular ($0.32 per share)	—	—	—	(23,798)	—	—	(23,798)
Common stock special ($0.79 per share)	—	—	—	(59,034)	—	—	(59,034)
Share-based compensation	—	—	12,398	—	—	—	12,398
Stock issued, net of forfeitures	898	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(5,329)	—	—	—	(5,329)
Other	—	—	2,197	(1,805)	—	—	392
Net income	—	—	—	71,984	—	—	71,984
Balances at December 31, 2012	75,250	$ 1	$396,186	$169,167	2,869	$(24,167)	$541,187

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Operating activities:			
Net income	$ 71,984	$ 172,817	$ 117,892
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	356,232	328,786	294,100
Amortization of debt issuance costs and premium	2,575	2,010	1,338
Loss on extinguishment of debt	—	22,694	—
Share-based compensation	12,398	9,710	5,533
Derivative (gain) loss	13,954	(1,896)	4,256
Cash payments on derivative settlements	(7,664)	(9,873)	874
Deferred income taxes	88,109	61,835	(8,266)
Changes in operating assets and liabilities:			
Oil and natural gas receivables	818	(18,639)	(24,933)
Joint interest and other receivables	(31,399)	375	25,897
Insurance receivables	2,576	20,771	54,873
Income taxes	(58,011)	(7,124)	104,067
Prepaid expenses and other assets	7,440	(7,809)	4,536
Asset retirement obligations	(112,827)	(59,958)	(87,166)
Accounts payable and accrued liabilities	38,026	7,881	(31,885)
Other liabilities	926	(102)	3,656
Net cash provided by operating activities	385,137	521,478	464,772
Investing activities:			
Acquisition of property interest in oil and natural gas properties	(205,550)	(437,247)	(236,944)
Investment in oil and natural gas properties and equipment	(479,313)	(281,779)	(178,709)
Proceeds from sales of oil and natural gas properties and equipment	30,453	15	1,420
Purchases of furniture, fixtures and other, net	(3,031)	(3,660)	(760)
Net cash used in investing activities	(657,441)	(722,671)	(414,993)
Financing activities:			
Issuance of 8.50% Senior Notes	318,000	600,000	—
Repurchase of 8.25% Senior Notes	—	(450,000)	—
Borrowings of long-term debt – revolving bank credit facility	732,000	623,000	627,500
Repayments of long-term debt – revolving bank credit facility	(679,000)	(506,000)	(627,500)
Repurchase premium and debt issuance costs	(8,510)	(32,288)	—
Dividends to shareholders	(82,832)	(58,756)	(59,609)
Other	379	1,094	298
Net cash provided by (used in) financing activities	280,037	177,050	(59,311)
Increase (decrease) in cash and cash equivalents	7,733	(24,143)	(9,532)
Cash and cash equivalents, beginning of period	4,512	28,655	38,187
Cash and cash equivalents, end of period	$ 12,245	$ 4,512	$ 28,655

See accompanying notes.

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

1. Significant Accounting Policies

Operations

W&T Offshore, Inc. and subsidiaries, referred to herein as "W&T" or the "Company," is an independent oil and natural gas producer focused primarily in the Gulf of Mexico and, more recently, onshore Texas. The Company is active in the exploration, development and acquisition of oil and natural gas properties.

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. Insurance receivables as of December 31, 2011 of $0.7 million were combined with *Joint interest and other receivables* on the Consolidated Balance Sheets.

Use of Estimates

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

Fiscal Year

Our fiscal year ends on December 31.

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 collectability is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties with joint ownership. Under this method, we record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which the Company has taken less than its ownership share of production. At December 31, 2012 and 2011, $6.0 million and $6.5 million, respectively, were included in current liabilities related to natural gas imbalances.

Concentration of Credit Risk

Our customers are primarily large integrated oil and natural gas companies and large financial institutions. Our production is sold utilizing month-to-month contracts that are based on bid prices. We also have receivables from joint interest owners on properties we operate and we may have the ability to withhold future revenue disbursements to recover amounts due us. We attempt to minimize our credit risk exposure to purchasers of our oil and natural gas, joint interest owners, derivative counterparties and other third-party entities through formal credit policies, monitoring procedures, and letters of credit or guaranties when considered necessary. We historically have not had any significant problems collecting our receivables except in rare circumstances. Accordingly, we do not maintain an allowance for doubtful accounts.

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

	Year Ended December 31,		
	2012	2011	2010
Customer			
Shell Trading (US) Co.	35%	36%	40%
ConocoPhillips (1)	16%	16%	17%
J.P. Morgan Ventures Energy Corp.	**	10%	**

** less than 10%

(1) ConocoPhillips split into two separate companies during 2012 and individually were approximately 8% each.

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

Insurance receivables

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

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 and all capitalized interest is recorded within *Oil and natural gas property and equipment* on the Consolidated Balance Sheet.

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

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 natural gas properties (including capitalized ARO), 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, 2012, 2011 and 2010 are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for that year and exclude future cash outflows related to capitalized ARO and include future development costs and ARO related to wells to be drilled.

Declines in oil and natural gas prices after December 31, 2012 may require us to record additional ceiling-test impairments in the future. We did not have any write-downs related to ceiling-test impairments during 2012, 2011 and 2010, respectively.

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.

Asset Retirement Obligations

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

Oil and Natural Gas Reserve Information

Pursuant to *Extractive Activities – Oil and Gas* topic of the Codification, we use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period when estimating quantities of proved reserves. Similarly, the prices used to calculate the standardized measure of discounted future cash flows and prices used in the ceiling test for impairment are the 12-month average commodity prices. Another provision of the guidance 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 21 for additional information about our proved reserves.

Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and interest rates. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our credit facility. Our derivative instruments currently consist of commodity swap and option contracts for oil. 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 and documentation criteria are met at the time the derivative contract is entered into. We have elected not to designate our commodity derivatives as hedging instruments, therefore all changes in fair value are recognized in earnings.

Fair Value of Financial Instruments

We include fair value information in the notes to our consolidated financial statements when the fair value of our financial instruments is different from the book value or it is required by applicable guidance. We believe that the book value of our cash and cash equivalents, receivables, accounts payable and accrued liabilities materially approximates fair value due to the short-term nature and the terms of these instruments. We believe that the book value of our restricted deposits approximates fair value as deposits are in cash or short-term investments. We believe the carrying amount of debt under our revolving bank credit facility approximates fair value because the interest rates are variable and reflective of market rates.

Fair Value of Acquisitions

Acquisitions are recorded on the closing date of the transaction at their fair value, which was determined by applying the market and income approaches using Level 3 inputs. The Level 3 inputs were: (i) analysis of comparable transactions obtained from various third-parties, (ii) estimates of ultimate recoveries of reserves, and (iii) estimates of discounted cash flows based on estimated reserve quantities, reserve categories, timing of production, costs to produce and develop reserves, future prices, ARO and discount rates. The estimates and assumptions were determined by management and third-parties. The fair value is based on subjective estimates and assumptions, which are inherently imprecise, and the actual realized values could vary significantly from these estimates. No goodwill was recorded for the acquisitions completed in 2012, 2011 or 2010.

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.

Debt Issuance 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 associated with all other debt are deferred and amortized over the scheduled maturity of the debt utilizing the effective interest method.

Premiums Received on Debt Issuance

Premiums are recorded in long-term liabilities and are amortized over the term of the related debt using the effective interest method.

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

Earnings Per Share

In accordance with the *Earnings Per Share* topic of the Codification, unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per share under the two-class method. For additional information, refer to Note 14.

Recent Accounting Developments

In December 2010, the FASB issued certain amendments to the *Business Combinations* topic of the Codification. The amendments specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual period. In addition, the supplemental pro forma disclosures related to pro forma adjustments were expanded. The amendments were effective for our fiscal year ended December 31, 2011. Early adoption was permitted and we elected to apply the amendments for the year 2010. These amendments only change disclosure requirements and not accounting practices; therefore, the adoption of these amendments did not have any impact on our financial position, results of operations or cash flows.

2. Acquisitions and Divestitures

2012 Acquisitions

On October 5, 2012, we acquired from Newfield Exploration Company and its subsidiary, Newfield Exploration Gulf Coast LLC (together, "Newfield") certain oil and gas leasehold interests (the "Newfield Properties"). The adjusted purchase price was $205.6 million, which was subject to certain adjustments, including adjustments from an effective date of July 1, 2012 until the closing date, and the assumption of future ARO. The purchase price may be subject to further adjustments. The properties consisted of leases covering 78 offshore blocks on approximately 416,000 gross acres (268,000 net acres) (excluding overriding royalty interests), comprised of 65 blocks in the deepwater, six of which are producing, 10 blocks on the conventional shelf, four of which are producing, and an overriding royalty interest in three deepwater blocks, two of which are producing. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand. Subsequently in the same month, the amounts borrowed under our revolving bank credit facility were paid down with funds provided from the issuance of $300.0 million of 8.50% Senior Notes (see Note 7).

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

Oil and natural gas properties and equipment	$237,214
Asset retirement obligations – current	(7,250)
Asset retirement obligations – non-current	(24,414)
Total cash paid	$205,550

Expenses associated with acquisition activities and transition activities related to the acquisition of the Newfield Properties for the year ended December 31, 2012 were $0.6 million and are included in general and administrative expenses ("G&A"). The acquisition was recorded at fair value, which was determined using both the market and income approaches and Level 3 inputs were used to determine fair value. See Note 1 for a description of the Level 3 inputs.

Revenue, Net Income and Pro Forma Financial Information – Unaudited

The Newfield Properties were not included in our consolidated results until the closing date of October 5, 2012. For the period of October 5, 2012 to December 31, 2012, the Newfield Properties accounted for $29.6 million of revenue, $5.4 million of direct operating expenses, $11.9 million of depreciation, depletion, amortization and accretion ("DD&A") and $4.3 million of income taxes, resulting in $8.0 million of net income. The net income attributable to these properties does not reflect certain expenses, such as G&A and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Newfield Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate.

The unaudited pro forma financial information was computed as if the acquisition of the Newfield Properties had been completed on January 1, 2011. The financial information was derived from W&T's audited historical consolidated financial statements, the Newfield Properties' audited historical financial statements for 2011 and the Newfield Properties' unaudited historical financial statement for 2012 interim period.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Newfield Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2011. If the transaction had been in effect for the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than Newfield. Realized sales prices for oil, NGLs and natural gas may have been different and costs of operating the Newfield Properties may have been different. The following table presents a summary of our pro forma financial information (in thousands except earnings per share):

	(unaudited) Year Ended December 31,	
	2012	2011
Revenue	$980,196	$1,187,808
Net income	77,059	220,875
Basic and diluted earnings per common share	1.01	2.92

For the pro forma financial information, certain information was derived from financial records and certain information was estimated. The sources of information and significant assumptions are described below:

(a) Revenues and direct operating expenses for the Newfield Properties were derived from the historical financial records of Newfield. Incremental revenue adjustments were $105.7 million and $216.8 million for 2012 and 2011, respectively. Incremental operating costs were $33.2 million and $24.6 million for 2012 and 2011, respectively.

(b) Incremental costs for insurance were estimated at $0.6 million annually, which were the incremental costs to add the Newfield Properties to W&T's insurance programs. The direct operating costs for the Newfield Properties described above excluded insurance costs.

(c) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Newfield Properties' costs, reserves and production into our currently existing full cost pool in order to compute such amounts. The purchase price allocation included $13.1 million that was allocated to the pool of unevaluated properties for oil and natural gas interests. Accordingly, no DD&A expense was estimated for the unevaluated properties. ARO were estimated by W&T management. Incremental DD&A was estimated at $53.4 million and $102.7 million for 2012 and 2011, respectively.

(d) Incremental transaction expenses related to the acquisition were $0.6 million and were assumed to be funded from cash on hand.

(e) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $205.6 million, which equates to the cash component of the transaction, and an interest rate of 7.7%, which equates to the effective yield on net proceeds for the additional senior notes issued shortly after the acquisition closed. Incremental interest expense was estimate at $12.0 million and $15.8 million for 2012 and 2011, respectively.

(f) Incremental capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings. Incremental capitalized interest was estimate at $0.6 million and $0.9 million for 2012 and 2011, respectively.

(g) Income tax expense was computed using the 35% federal statutory rate. Incremental income tax expense was estimated at $2.7 million and $25.9 million for 2012 and 2011, respectively.

(h) The 2011 period does not include any pro forma adjustments related to the 2011 acquisitions as described below.

2011 Acquisitions

On May 11, 2011, we acquired from Opal Resources LLC and Opal Resources Operating Company LLC (collectively, "Opal") certain oil and gas leasehold interests (the "Yellow Rose Properties"). The adjusted purchase price was $394.4 million, which was subject to certain adjustments, including adjustments from an effective date of January 1, 2011 until the closing date, and we assumed the future ARO and a certain long-term liability. The properties consisted of approximately 24,500 gross acres (21,900 net acres) of oil and gas leasehold interests in the West Texas Permian Basin. The acquisition was funded from cash on hand and borrowings under our revolving bank credit facility.

The following table presents the purchase price allocation for the acquisition of the Yellow Rose Properties (in thousands):

Oil and natural gas properties and equipment	$396,902
Asset retirement obligations – non-current	(382)
Long-term liability	(2,143)
Total cash paid	$394,377

On August 10, 2011, we acquired from Shell Offshore Inc. ("Shell") certain oil and gas leasehold and property interests (the "Fairway Properties"). The adjusted purchase price was $42.9 million, which was subject to certain adjustments, including adjustments from an effective date of September 1, 2010 until the closing date, and we assumed the future ARO. The properties consisted of Shell's 64.3% interest in the Fairway Field along with a like interest in the associated Yellowhammer gas treatment plant. The acquisition was funded from borrowings under our revolving bank credit facility.

The following table presents the purchase price allocation for the acquisition of the Fairway Properties (in thousands):

Oil and natural gas properties and equipment	$50,682
Asset retirement obligations – non-current	(7,812)
Total cash paid	$42,870

Expenses associated with acquisition activities and transition activities related to the Yellow Rose Properties and Fairway Properties for the year 2011 were $1.6 million and are included in G&A. The acquisitions were recorded at fair value, which was determined using both the market and income approaches and Level 3 inputs were used to determine fair value. See Note 1 for a description of the Level 3 inputs.

Revenue, Net Income and Pro Forma Financial Information – Unaudited

The Yellow Rose Properties and the Fairway Properties were not included in our consolidated results until their respective close dates. For the period of May 11, 2011 to December 31, 2011 for the Yellow Rose Properties and the period of August 10, 2011 to December 31, 2011 for the Fairway Properties, these two acquisitions accounted for $64.0 million of revenue, $25.5 million of direct operating expenses, $20.5 million of DD&A and $6.3 million of income taxes, resulting in $11.7 million of net income. The net income attributable to these properties does not reflect certain expenses, such as G&A and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Yellow Rose Properties and the Fairway Properties were not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate.

The unaudited pro forma financial information was computed as if these two acquisitions had been completed on January 1, 2010. The historical financial information is derived from W&T's audited historical consolidated financial statements, the Yellow Rose Properties' audited historical financial statement for 2010, the Fairway Properties' unaudited historical statement for 2010 and the unaudited historical statement of the sellers for the 2011 interim periods.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Yellow Rose Properties and the Fairway Properties. The pro forma financial information is not necessarily indicative of the results of operations had the respective purchases occurred on January 1, 2010. If the transactions had been in effect for the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than the sellers. Realized sales prices for oil, NGLs and natural gas may have been different and costs of operating the properties may have been different. The following table presents a summary of our pro forma financial information (in thousands except earnings per share):

	(unaudited) Year Ended December 31,	
	2011	**2010**
Revenue	$1,023,430	$784,964
Net income	180,779	113,783
Basic and diluted earnings per common share	2.39	1.52

For the pro forma financial information, certain information was derived from financial records and certain information was estimated. The sources of information and significant assumptions are described below:

(a) Revenues and direct operating expenses for the Yellow Rose Properties and the Fairway Properties were derived from the historical records of the sellers up to the respective closing dates. Incremental revenue adjustments were $52.4 million and $79.2 million for 2011 and 2010, respectively. Incremental operating costs were $16.4 million and $25.3 million for 2011 and 2010, respectively.

(b) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Yellow Rose Properties and Fairway Properties' costs, reserves and production into our currently existing full cost pool in order to compute such amounts. The purchase price allocation included $81.2 million that was allocated to the pool of unevaluated properties for oil and gas interests. Accordingly, no DD&A expense was estimated for the unevaluated properties. ARO were estimated by W&T management. Incremental DD&A was estimated at $21.9 million and $50.4 million for 2011 and 2010, respectively.

(c) Incremental transaction expenses related to the acquisitions completed during 2011 were $1.6 million and were assumed to be funded from cash on hand. These were adjusted from 2011 results.

(d) The acquisitions were assumed to be funded with borrowed funds and that borrow capacity would have been available on the revolving bank credit facility due to the increase in reserves. Interest expense was computed using interest rates that were in effect during the applicable time period and we assumed that six-month London Interbank Offered Rate ("LIBOR") borrowings were made as allowed under the revolving bank credit facility. The assumed interest rates ranged from 3.1% to 3.5%. A reduction in the revolving bank credit facility commitment fee related to the assumed borrowings was netted against the computed incremental interest expense. Incremental interest expense was estimate at $4.6 million and $12.9 million for 2011 and 2010, respectively.

(e) Incremental capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings. Incremental capitalized interest was estimate at $1.1 million and $3.0 million for 2011 and 2010, respectively.

(f) Income tax expense was computed using the 35% federal statutory rate. Incremental income tax expense was estimated at $4.3 million for 2011 and an income tax benefit was estimated at $2.2 million for 2010.

(g) The 2011 period does not included any pro forma adjustments related to the 2012 acquisition described above. The 2010 period does not include any pro forma adjustments related to the 2010 acquisitions as described below.

2010 Acquisitions

On April 30, 2010, we acquired from Total E&P USA ("Total E&P") certain oil and gas leasehold interest (the "Total Properties"). The acquisition was made through our wholly-owned subsidiary, W&T Energy VI, LLC ("Energy VI"). The adjusted purchase price was $115.0 million, which was subject to certain adjustments, including adjustments from an effective date of January 1, 2010 until the closing date, and we assumed the future ARO. The properties acquired were Total E&P's interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico. The properties included a 100% working interest in the Matterhorn field (Mississippi Canyon block 243) and a 64% working interest in the Virgo field (Viosca Knoll blocks 822 and 823). The acquisition was funded with cash on hand. In accordance with the Purchase and Sale Agreement, Energy VI obtained unsecured surety bonds in favor of the Bureau of Ocean Energy Management (the "BOEM") to secure the ARO with respect to these assets. The Purchase and Sale Agreement provides for annual increases in the required security for the ARO. To help satisfy the annual increases, Energy VI has agreed to make periodic payments from production of the acquired properties to an escrow agent. As long as the required security amount then in effect is met, the payments will be promptly released to us by the escrow agent. As of December 31, 2012, we were in compliance with the required security amount.

The following table presents the purchase price allocation for the acquisition of the Total Properties (in thousands):

Oil and natural gas properties and equipment	$121,301
Asset retirement obligations – non-current	(6,289)
Total cash paid	$115,012

On November 4, 2010, through Energy VI, we acquired from Shell certain oil and gas leasehold interest (the "Tahoe Properties"). The adjusted purchase price was $116.2 million, subject to certain adjustments, including adjustments from an effective date of September 1, 2010, and we assumed the future ARO. The properties acquired were Shell's interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico. The properties included a 70% working interest in the Tahoe field (Viosca Knoll 783), 100% working interest in the Southeast Tahoe field (Viosca Knoll 784) and a 6.25% of 8/8ths overriding royalty interest in the Droshky field (Green Canyon 244). The acquisition was funded with cash on hand. In accordance with the Purchase and Sale Agreement, Energy VI obtained unsecured surety bonds to secure the ARO with respect to these assets.

The following table presents the purchase price allocation for the acquisition of the Tahoe Properties (in thousands):

Oil and natural gas properties and equipment	$134,189
Asset retirement obligations – non-current	(17,956)
Total cash paid	$116,233

Expenses associated with acquisition activities and transition activities related to the Total Properties and Tahoe Properties for the year 2010 were $0.5 million and are included in G&A. The acquisitions were recorded at fair value, which was determined using both the market and income approaches and Level 3 inputs were used to determine fair value. See Note 1 for a description of the Level 3 inputs.

Revenue, Net Income and Pro Forma Financial Information – Unaudited

The Total Properties and the Tahoe Properties were not included in our consolidated results until their respective close dates. For the period of April 30, 2010 to December 31, 2010 for the Total Properties and the period of November 4, 2010 to December 31, 2010 for the Tahoe Properties, these two acquisitions accounted for $97.2 million of revenue, $19.9 million of direct operating expenses, $27.9 million of DD&A and $17.3 million of income taxes, resulting in $32.1 million of net income. The net income attributable to these properties does not reflect certain expenses, such as G&A and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis.

The unaudited pro forma financial information was computed as if these two acquisitions had been completed on January 1, 2009. The historical financial information is derived from W&T's audited historical consolidated financial statements and the unaudited historical statements of the sellers.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Total Properties and the Tahoe Properties. The pro forma financial information is not necessarily indicative of the results of operations had the respective purchases occurred on January 1, 2009. If the transactions had been in effect for the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than the sellers. Realized sales prices for oil, NGLs and natural gas sales prices may have been different and costs of operating the properties may have been different. The following table presents a summary of our pro forma financial information (in thousands except earnings per share):

	(unaudited) Year Ended December 31, 2010
Revenue	$818,230
Net income	148,359
Basic and diluted earnings per common share	1.99

For the pro forma financial information, certain information was derived from financial records and certain information was estimated. The sources of information and significant assumptions are described below:

(a) Revenues and direct operating expenses for the Total Properties and the Tahoe Properties were derived from the historical records of the sellers for the period of January 1, 2010 to the respective closing dates. Incremental revenues and operating expenses for 2010 were $112.4 million and $25.3 million, respectively.

(b) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Total Properties and the Tahoe Properties' costs, reserves and production into our currently existing full cost pool in order to compute such amounts. ARO and related accretion were estimated by W&T management. Incremental DD&A was estimated at $39.6 million.

(c) Incremental transaction expenses related to the acquisitions completed during 2010 were $0.5 million and were assumed to be funded from cash on hand. These were adjusted from 2010 results.

(d) Reductions in interest income were computed related to cash paid for the acquisitions as cash on hand was sufficient to fund the acquisitions as of January 1, 2009. Average interest rates earned on short-term investments for the respective years were used in determining the adjustment. Decrease in interest income was estimated at $1.1 million.

(e) An incremental income tax rate of 35% was used in the calculations for the estimated incremental earnings before taxes. Incremental income taxes were estimated at $16.4 million.

(f) The 2010 period does not included any pro forma adjustments related to the 2011 acquisitions described above.

2012 Divestitures

On May 15, 2012, we sold our 40%, non-operated working interest in the South Timbalier 41 field located in the Gulf of Mexico for $30.5 million, net, with an effective date of April 1, 2012. The transaction was structured as a like-kind exchange under the Internal Revenue Service Code ("IRC") Section 1031 and other applicable regulations, with funds held by a qualified intermediary until replacement purchases could be executed. Replacement purchases were consummated during 2012. In connection with this sale, we reversed $4.0 million of ARO.

3. Hurricane Remediation and Insurance Claims

During the third quarter of 2008, Hurricane Ike and, to a much lesser extent, Hurricane Gustav caused property damage and disruptions to our exploration and production activities. Our insurance policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention requirement of $10.0 million per occurrence to be satisfied by us before we could be indemnified for losses. In the fourth quarter of 2008, we satisfied our $10.0 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 $150.0 million for property damage due to named windstorms (excluding certain damage incurred at our facilities of marginal significance) and $250.0 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 below our retention amount. Below is a summary of remediation costs and amounts approved for payments related to Hurricanes Ike and Gustav that were included in lease operating expense (in thousands), with bracketed amounts representing credits to expense:

	Year Ended December 31,		
	2012	2011	2010
Incurred and reversals of accruals	$1,022	$ 132	$ (1,380)
Plus amounts returned to insurers	—	1,241	—
Less amounts approved for payment by insurers	(146)	(1,334)	(10,350)
Included in lease operating expenses	$ 876	$ 39	$(11,730)

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection, which arises when our insurance underwriters' adjuster reviews and approves such costs for payment by the underwriters. Claims that have been processed in this manner have customarily been paid on a timely basis. Incurred expenses included revisions of previous estimates. Amounts in 2011 include return of reimbursements that were previously received by us related to prepayments based on preliminary estimates. In 2010, incurred expenses were a credit due to revisions of previous estimates. See Note 5 for additional information about the impact of hurricane related items on our asset retirement obligations. See Note 18 for information regarding legal actions taken by certain insurers and the Company.

Below is a reconciliation of our insurance receivables (in thousands):

Balance, December 31, 2011	$ 715
Costs approved under our insurance policies, net	2,221
Payments received, net	(2,936)
Balance, December 31, 2012	$ —

At December 31, 2011, substantially all of the amounts in insurance receivables relate to the plugging and abandonment of wells and dismantlement of facilities damaged by Hurricane Ike. Insurance receivables are included in *Joint interest and other receivables* on the Consolidated Balance Sheets.

From the third quarter of 2008 through December 31, 2012, we have received $142.2 million from our insurance carrier related to Hurricane Ike. To the extent that additional remediation cost or plug and abandonment costs are incurred that are not covered by insurance, we expect that our available cash and cash equivalents, cash flow from operations and the availability under our revolving bank credit facility will be sufficient to meet necessary expenditures that may exceed our insurance coverage for damages incurred as a result of Hurricane Ike.

4. Restricted Deposits

Restricted deposits as of December 31, 2012 and 2011 consisted of funds escrowed for the future plugging and abandonment of certain oil and natural gas properties.

Pursuant to the Purchase and Sale Agreement with Total E&P, security for future plugging and abandonment of certain oil and natural gas properties is required either through bonds or payments to an escrow account or a combination. Monthly payments are made to an escrow account and these funds are returned once verification is made as to fulfilling the security amount requirements. We were in compliance with the security requirements as of December 31, 2012. See Note 16 for potential future security requirements.

5. Asset Retirement Obligations

Pursuant to the *Asset Retirement and Environmental Obligations* topic of the Codification, an asset retirement obligation 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. The fair value of the ARO is measured using expected cash outflows associated with the ARO, discounted at our credit-adjusted risk-free rate when the liability is initially recorded. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

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

	2012	2011
Asset retirement obligations, beginning of period	$ 393,880	$391,316
Liabilities settled	(112,827)	(59,958)
Accretion of discount	20,055	29,771
Disposition of properties	(3,993)	—
Liabilities assumed through acquisition	31,664	8,194
Liabilities incurred	1,815	565
Revisions of estimated liabilities due to Hurricane Ike	(20,616)	4,744
Revisions of estimated liabilities – all other	74,075	19,248
Asset retirement obligations, end of period	384,053	393,880
Less current portion	92,630	138,185
Long-term	$ 291,423	$255,695

Each year (or more often if conditions warrant) we review and, to the extent necessary, revise our ARO estimates. During 2012, we reduced our ARO by $112.8 million for the plug and abandonment work performed during the year (including reductions of $29.6 million to plug and abandon wells and facilities damaged by Hurricane Ike). The acquisition of the Newfield Properties caused an increase of $31.7 million. Revisions made related to Hurricane Ike were a net decrease of $20.6 million, which was primarily attributable to the designation of a reef in place at one of the hurricane damaged platforms. Other revisions increased ARO by $74.1 million and were attributable to: a) regulation interpretations issued by the Bureau of Safety and Environmental Enforcement (which increased the amount of work involved), b) revisions to third-party contractor estimate prices for certain work on wells and structures, c) revisions accelerating the timing of planned work for certain wells, and d) revisions for certain wells that are taking longer to complete the plugging and abandoning work than previously estimated due to operational issues. In addition, increases in estimates were made for certain non-operated properties.

During 2011, we reduced our ARO by $60.0 million for the plug and abandonment work performed during the year (including $23.0 million to plug and abandon wells and facilities damaged by Hurricane Ike). Offsetting this decrease were the acquisitions of properties, including the Yellow Rose Properties and the Fairway Properties, which increased our obligations by $8.2 million. In addition, revisions were made related to Hurricane Ike, which increased the liability by $4.7 million. Other estimates were increased by $19.2 million primarily attributable to changes in estimates for certain non-operated properties and accelerating the expected timing of performing some of the work.

6. Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and interest rates. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. Our derivative instruments currently consist of crude oil swap and option contracts. All of the derivative counterparties are also lenders or affiliates of lenders participating in our revolving bank credit facility. We are exposed to credit loss in the event of nonperformance by the derivative counterparties; however, we do not currently anticipate that any of our derivative counterparties will be unable to fulfill their contractual obligations. Additional collateral is not required by us due to the derivative counterparties' collateral rights as lenders and we do not require collateral from our derivative counterparties. Our derivative agreements allow for netting of derivative gains and losses upon settlement. If an event of default were to occur causing an acceleration of payment under our revolving bank credit facility, that event may also trigger an acceleration of settlement of our derivative instruments.

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

Commodity Derivatives. We have entered into commodity option contracts to manage a portion of our exposure to commodity price risk from sales of oil through December 2014. While these contracts are intended to reduce the effects of price volatility, they may also limit future income from favorable price movements. During 2012 and 2011, our commodity derivative contracts consisted entirely of crude oil contracts. During 2010, our commodity derivative contracts consisted of oil and natural gas contracts. The swaps are priced off the Brent crude oil price quoted on the IntercontinentalExchange, known as ICE. Although our Gulf of Mexico crude oil is based off the WTI crude oil price plus a premium, the realized prices received for the types of crude oil have been closer to the Brent crude oil price because of competition with foreign supplied crude oil, which is based off the Brent crude oil price. Therefore, we entered into swap oil contracts priced off the Brent crude oil price to mitigate a portion of the price risk associated with our Gulf of Mexico crude oil production.

As of December 31, 2012, our open commodity derivative contracts were as follows:

Swaps – Oil (ICE)				
Termination Period		Notional Quantity (Bbls)	Weighted Average Contract Price	Fair Value Liability (in thousands)
2013:	1st quarter	351,000	$101.97	$2,566
	2nd quarter	336,700	101.97	1,843
	3rd quarter	312,800	101.98	1,205
	4th quarter	294,400	101.98	741
2014:	1st quarter	180,000	97.38	1,085
	2nd quarter	172,900	97.38	863
	3rd quarter	165,600	97.38	647
	4th quarter	156,400	97.37	451
		1,969,800	$100.40	$9,401

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

	December 31, 2012	December 31, 2011
Prepaid and other assets	$ —	$2,341
Other assets	—	1,746
Accrued liabilities	6,355	7,199
Other liabilities	3,046	—

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

	Year Ended December 31, 2012	2011	2010
Derivative (gain) loss:			
Realized	$ 7,665	$ 9,873	$(5,539)
Unrealized	6,289	(11,769)	9,511
Total	$13,954	$ (1,896)	$ 3,972

Interest Rate Swap

Changes in the fair value of our interest derivative contract are recognized currently in earnings. Our interest rate swap contract with a fixed interest rate of 5.21% expired in August 2010. During 2010, we recognized an unrealized gain of $4.4 million and a realized loss of $4.7 million for this contract.

7. Long-Term Debt

As of December 31, 2012 and 2011 our long-term debt was as follows (in thousands):

	December 31,	
	2012	2011
8.50% Senior Notes, due June 2019	$ 900,000	$600,000
Debt premiums, net of amortization	17,611	—
Revolving bank credit facility due May 2015	170,000	117,000
Total long-term debt (1)	1,087,611	717,000
Current maturities of long-term debt	—	—
Long-term debt, less current maturities	$1,087,611	$717,000

(1) Aggregate annual maturities of long-term debt as of December 31, 2012 are as follows (in millions): 2013 – $0.0; 2014 – $0.0; 2015 – $170.0; 2016 – $0.0; thereafter – $900.0.

Senior Notes

On October 24, 2012, we issued $300.0 million of Senior Notes at a premium of 106% par value with an interest rate of 8.50% (7.73% effective interest rate) and maturity date of June 15, 2019, which have identical terms to the Senior Notes issued in June 2011 (collectively, the "8.50% Senior Notes"). The net proceeds after fees and expenses were approximately $312.0 million. The funds were used to repay all of our outstanding indebtedness under our revolving bank credit facility, a portion of which was incurred to partially fund our acquisition of the Newfield Properties described in Note 2, and for general corporate purposes. In February 2013, holders of the Senior Notes issued in October 2012 exchanged their Senior Notes for registered notes with the same terms.

On June 10, 2011, we issued $600.0 million of Senior Notes at par with an interest rate of 8.50% and maturity date of June 15, 2019. The net proceeds after fees and expenses were approximately $593.5 million. In January 2012, holders of the Senior Notes issued in June 2011 exchanged their Senior Notes for registered notes with the same terms.

In June and July of 2011, we used a portion of the net proceeds from the June 2011 issuance of the 8.50% Senior Notes to repurchase all of our 8.25% Senior Notes due 2014 (the "8.25% Senior Notes"), which had a principal amount of $450.0 million. Costs of $22.0 million related to repurchasing the 8.25% Senior Notes, which included repurchase premiums and the unamortized debt issuance costs, are included in the statement of income within the line item classification, *Loss on extinguishment of debt.*

Interest on the 8.50% Senior Notes is payable semi-annually in arrears on June 15 and December 15 of each year and all of the 8.50% Senior Notes are subject to the same indenture. The 8.50% Senior Notes are unsecured and are fully and unconditionally guaranteed by certain of our subsidiaries. At December 31, 2012 and 2011, the outstanding balance of our 8.50% Senior Notes was $900.0 million and $600.0, respectively, and was classified at their carrying value as long-term debt. The estimated annual effective interest rate on the 8.50% Senior Notes is 8.6% for 2012 which includes amortization of debt issuance costs and premiums. At December 31, 2012 and 2011, the estimated fair value of the 8.50% Senior Notes was approximately $963.0 million and $612.0 million, respectively.

We and our restricted subsidiaries are subject to certain covenants under the indenture governing the 8.50% Senior Notes, which limit our and our restricted subsidiaries' ability to, among other things, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of our assets, engage in transactions with affiliates, pay dividends or make other distributions on capital stock or subordinated indebtedness and create unrestricted subsidiaries. We were in compliance with all applicable covenants of the indenture governing the 8.50% Senior Notes as of December 31, 2012.

Credit Agreement

On May 5, 2011, we entered into the Fourth Amended and Restated Credit Agreement (the "Credit Agreement"), which provides a revolving bank credit facility with an initial borrowing base of $525.0 million. In November 2012, the borrowing base was re-determined by our lenders and increased to $725.0 million. This is a secured facility that is collateralized by our oil and natural gas properties. The Credit Agreement terminates on May 5, 2015 and replaced the prior Third Amended and Restated Credit Agreement (the "Prior Credit Agreement"). Availability under the Credit Agreement is subject to a semi-annual borrowing base determination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility.

The Credit Agreement contains covenants that limit, among other things, the payment of cash dividends of up to $60.0 million per year, common stock repurchases and Senior Note repurchases of up to $100.0 million, borrowings other than from the revolving bank credit facility, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. In December 2012, we were granted a one-time waiver which allowed for cash dividends of up to $85.0 million during 2012. Letters of credit may be issued for up to $90.0 million, provided availability under the revolving bank credit facility exists. 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. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2012.

Borrowings under the revolving bank credit facility bear interest at the applicable LIBOR plus a margin that varies from 2.00% to 2.75% depending on the level of total borrowings under the Credit Agreement, or an alternative base rate equal to the applicable margin ranging from 1.00% to 1.75% plus the highest of the (a) Prime Rate, (b) Federal Funds Rate plus 0.50%, and (c) LIBOR plus 1.0%. The unused portion of the borrowing base is subject to a commitment fee of 0.50%. The estimated annual effective interest rate was 5.0% for 2012 for borrowings under the Credit Agreement. The estimated annual effective interest rate includes amortization of debt issuance costs and excludes commitment fees and other costs.

On May 7, 2012, we executed the First Amendment to the Fourth Amended and Restated Credit Agreement which, among other things, increased the number of participating lenders and added a provision permitting the Company to maintain security interests in favor of any derivative counterparties that cease to be lenders under the Company's revolving bank credit facility. On October 12, 2012, we executed the Second Amendment to the Fourth Amended and Restated Credit Agreement, which, among other things, allowed for the issuance of additional Senior Notes above the $600.0 million level and provided for a reduction in the borrowing base of

25% of every $1.00 of Senior Notes above $600.0 million until such time as the borrowing base is re-determined. The borrowing base was re-determined subsequent to this amendment. All other terms of the Credit Agreement remain substantially the same prior to the Amendment.

Unamortized debt issuance costs of $0.7 million related to the Prior Credit Agreement were written off in 2011 and are included in the statement of income within the line item classification, *Loss on extinguishment of debt*.

At December 31, 2012, we had $170.0 million in borrowings and $0.6 million in letters of credit outstanding under the revolving bank credit facility. At December 31, 2011, we had $117.0 million in borrowings and $0.4 million in letters of credit outstanding under the revolving bank credit facility.

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

8. Fair Value Measurements

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.

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

		December 31,			
		2012		2011	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$ —	$ 9,401	$4,087	$ 7,199
8.50% Senior Notes	Level 2	—	963,000	—	612,000
Revolving bank credit facility	Level 2	—	170,000	—	117,000

Derivatives are reported in the statement of financial position at fair value. The 8.50% Senior Notes are reported in the statement of financial position at their carrying value, which was $900.0 million and $600.0 million at December 31, 2012 and 2011, respectively. The revolving bank credit facility debt is reported in the statement of financial position at its carrying value, which was $170.0 million and $117.0 million at December 31, 2012 and 2011, respectively.

We measure the fair value of our derivative financial instruments by applying the income approach and using inputs that are classified within Level 2 of the valuation hierarchy. The inputs used for our derivative financial instruments fair value measurement are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads and published commodity futures prices. The fair value of our Senior Notes is based on quoted prices and the market is not an active market; therefore, the fair value is classified within Level 2. The carrying amount of debt under our revolving bank credit facility approximates fair value because the interest rates are variable and reflective of market rates. For additional information about our derivative financial instruments refer to Note 6 and for additional information on our Senior Notes and revolving bank credit facility refer to Note 7.

9. Equity Structure and Transactions

As of December 31, 2012 and 2011, the Company was authorized to issue 20 million shares and two million shares, respectively, of preferred stock with a par value of $0.00001 per share; however, no preferred shares have been issued or were outstanding as of the respective dates.

During 2012, 2011 and 2010, we paid regular cash dividends of $0.32, $0.16 and $0.14 common share per year, respectively. In December, 2012, we paid two special dividends totaling $0.79 per share or $59.0 million. In December, 2011, we paid a special dividend of $0.63 per share or $46.9 million. In December, 2010, we paid a special dividend of $0.66 per share or $49.2 million. On February 26, 2013, our board of directors declared a cash dividend of $0.08 per common share, payable on March 29, 2013 to shareholders of record on March 15, 2013.

10. Incentive Compensation Plan

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

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

For 2012, performance awards under the Plan were granted in the form of restricted stock units ("RSUs") and cash awards. As defined by the Plan, RSUs are rights to receive stock, cash or a combination thereof at the end of a specified vesting period, subject to certain terms and conditions as determined by the Committee. RSUs are a long-term compensation component of the Plan, which are granted to only certain employees, and are subject to adjustments at the end of the applicable performance period based on the Company achieving certain predetermined performance criteria. For 2012, 70% of the RSUs award was conditioned on achieving earnings per share targets for 2012, 10% of the RSUs award was conditioned on achieving total shareholder return ("TSR") targets for 2012, 10% of the RSUs award was conditioned on achieving TSR targets for 2013 and 10% of the RSUs award was conditioned on achieving TSR targets for the period January 1, 2014 to October 31, 2014 (collectively, the "2012 RSUs"). TSR is determined based upon the change in the entity's stock price plus dividends for the applicable performance period. The TSR targets are the ranking of the Company's TSR compared to the TSR of 19 peer companies. The 2012 RSUs related to the earnings per share targets have an issuance scale from 0% to 100%. The 2012 RSUs related to TSR targets have an issuance scale from 0% to 150%. Vesting for the 2012 RSUs occurs on December 15, 2014.

The fair value at the date of grant for the 2012 RSUs was determined separately for the component related to the earnings per share targets and the component related to TSR targets. The fair value of the component related to earnings per share targets was determined using the Company's closing price on the grant date. The fair value for the component related to TSR targets was determined by using a Monte Carlo simulation probabilistic model. The inputs used in the probabilistic model for the Company and the peer companies were: average closing stock prices during January 2012; risk-free interest rates using the LIBOR ranging from 0.15% to 0.72% over the service period; expected volatilities ranging from 33% to 74%; expected dividend yields ranging from 0.0% to 2.5%; and correlation factors ranging from (67%) to 94%. The expected volatilities, expected dividends and correlation factors were developed using historical data.

For 2012, some of the RSUs that were granted to employees were forfeited as the Company did not meet certain predefined performance measures including earnings per share and TSR targets. Pursuant to the Plan, discretionary authority was exercised for certain non-executive employees, which reduced the forfeitures that would have occurred through application of the predefined performance measurement. Vesting eligibility for the TSR component of RSUs for the 2013 and 2014 periods will be determined at the end of the respective performance periods. With the exception of the 2012 RSU components that relate to TSR for the 2013 and 2014 performance periods, the remaining 2012 RSUs not forfeited will be eligible for vesting in December 2014, subject to meeting certain employment criteria. The cash-based awards, which are a short-term component of the Plan, were determined based on multiple performance measures, such as earnings per share, reserve and production growth, cost containment and individual performance measures. With respect to the 2012 cash-based awards, some of the performance criteria targets were achieved and were combined with estimates of personal performance measurements to determine potential payments. In addition, pursuant to the Plan, discretionary authority was exercised for certain non-executive employees, which increased cash-based award amounts. Employees will be paid their cash-based awards within 75 days following year end 2012.

For 2011, performance awards under the Plan were granted in the form of RSUs and cash awards. The sole business performance criteria established for the 2011 RSU awards (the "2011 RSUs") was an earnings per share target. The Company exceeded the top-tier target; therefore 100% of the 2011 RSUs awards will be eligible for vesting on December 15, 2013. The fair value of the 2011 RSUs was estimated by using the Company's closing price on the grant date. The cash-based awards, which are a short-term component of the Plan, were determined based on multiple performance measures, such as earnings per share, reserve and production growth, cost containment and individual performance measures. With respect to the 2011 cash-based awards, most of the performance criteria targets were achieved and were combined with the individual's performance to determine the cash-based award paid.

For 2010, performance awards under the Plan were granted in the form of RSUs and cash awards. The sole business performance criteria established for the 2010 RSU awards (the "2010 RSUs") was an earnings per share target. The Company exceeded the top-tier target; therefore 100% of the 2010 RSUs awards were eligible for vesting on December 15, 2012. The fair value of the 2010 RSUs was estimated by using the Company's closing price on the grant date. The cash based awards were determined based on multiple performance measures. With respect to the 2010 cash-based awards, most of the performance criteria targets were achieved and were combined with the individual's performance to determine the cash-based award paid.

For information concerning grants awarded and amounts recognized in lease operating expense and G&A, see Note 11.

11. Share-Based and Cash-Based Incentive Compensation

As allowed by the Plan, in 2012, 2011 and 2010, the Company granted RSUs to certain of its employees. In 2012 and in prior years, restricted stock was granted to the Company's non-employee directors under the Directors Compensation Plan. In addition to share-based compensation, the Company granted its employees cash-based incentive awards in 2012, 2011 and 2010.

At December 31, 2012, there were 1,393,602 shares of common stock available for award under the Plan and 546,829 shares of common stock available for award under the Directors Compensation Plan.

Restricted Stock

Under the Company's share-based payment plans, restricted shares were issued in 2012, 2011 and 2010 primarily to the Company's non-employee directors. Restricted shares are subject to forfeiture until vested and cannot be sold, transferred or otherwise 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. The fair value of restricted stock was estimated by using the Company's closing price on the grant date.

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

	2012		2011		2010	
	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	51,870	$15.81	470,392	$ 7.42	1,050,506	$ 8.48
Granted	21,954	19.13	20,433	25.45	35,000	10.00
Vested	(27,475)	13.59	(404,422)	7.31	(485,934)	9.69
Forfeited	(2,662)	18.78	(34,533)	6.83	(129,180)	8.15
Nonvested, end of period	43,687	18.69	51,870	15.81	470,392	7.42

Subject to the satisfaction of service conditions, the restricted shares outstanding as of December 31, 2012 will vest as follows:

	Shares
2013	24,019
2014	12,354
2015	7,314
Total	43,687

Restricted stock fair value at grant date and vested date: The grant date fair value of restricted stock granted during 2012, 2011 and 2010 was $0.4 million, $0.5 million and $0.4 million, respectively. The fair value of the restricted stock that vested during 2012, 2011 and 2010 was $0.5 million, $7.9 million and $8.1 million, respectively, based on the closing prices on the dates of vesting.

Restricted Stock Units

During 2012, 2011 and 2010, the Company awarded to certain employees RSUs that were 100% contingent upon meeting specified performance requirements. The specific performance requirements were partially achieved in 2012 and were fully achieved in 2011 and 2010. Vesting occurs upon completion of the specified vesting period applicable to each award. Subsequent to the determination of the performance achievement and prior to vesting, the RSUs awards earn dividend equivalents at the same rate as dividends paid on our common stock. RSUs awarded are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted period. The methodology and assumptions used to estimate fair value for RSUs grants are described in Note 10.

A summary of share activity related to RSUs is as follows:

	2012		2011		2010	
	RSUs	Weighted Average Grant Date Price Per Share	RSUs	Weighted Average Grant Date Price Per Share	RSUs	Weighted Average Grant Date Price Per Share
Nonvested, beginning of period	1,732,703	$14.67	1,266,617	$ 9.36	—	$ —
Granted	764,654	18.64	534,375	26.93	1,280,501	9.36
Vested	(1,198,208)	9.36	—	—	—	—
Forfeited (1)	(329,329)	19.56	(68,289)	12.03	(13,884)	9.36
Nonvested, end of period	969,820	22.70	1,732,703	14.67	1,266,617	9.36

(1) Includes RSUs forfeited due to adjustment for performance related to earnings per share targets and TSR targets.

Subject to the satisfaction of service conditions, the RSUs outstanding as of December 31, 2012 will vest as follows:

	Shares
2013	475,689
2014	494,131
Total	969,820

RSUs fair value at grant date and vested date: During 2012, 2011 and 2010, the grant date fair value of RSUs granted was $14.3 million, $14.4 million and $12.0 million, respectively. The fair value of the RSUs that vested during 2012 was $20.0 million based on the opening price on the first day of trading after the vesting date, as vesting occurred on a weekend.

Share-Based Compensation

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

	Year Ended December 31,		
	2012	2011	2010
Share-based compensation expense from:			
Restricted stock	$ 399	$2,377	$3,469
Restricted stock units	11,999	7,333	2,064
Total	$12,398	$9,710	$5,533
Share-based compensation tax benefit:			
Tax benefit computed at the statutory rate	$ 4,339	$3,399	$1,937

As of December 31, 2012, unrecognized share-based compensation expense related to our issued restricted shares and RSUs was $0.5 million and $11.4 million, respectively. Unrecognized compensation expense will be recognized through April 2015 for restricted shares and November 2014 for RSUs.

Cash-based Incentive Compensation

As defined by the Plan, annual incentive awards payable in cash may be granted to eligible employees. These awards are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each of such criteria. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year.

Share-Based Compensation and Cash-Based Incentive Compensation Expense

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

	Year Ended December 31,		
	2012	2011	2010
Share-based compensation expense included in:			
Lease operating expense	$ —	$ 466	$ 748
General and administrative	12,398	9,244	4,785
Total charged to operating income	12,398	9,710	5,533
Cash-based incentive compensation included in:			
Lease operating expense	3,787	3,700	2,067
General and administrative	6,558	12,213	8,539
Total charged to operating income	10,345	15,913	10,606
Total incentive compensation charged to operating income	$22,743	$25,623	$16,139

12. Employee Benefit Plan

We maintain a defined contribution benefit plan in compliance with Section 401(k) of the IRC (the "401(k) Plan"), which covers those employees who meet the 401(k) Plan's eligibility requirements. During 2012, 2011 and 2010, the Company's matching contribution was 100% of each participant's contribution up to a maximum of 6% for 2012 and 5% for prior years of the participant's eligible compensation, subject to limitations imposed by the Internal Revenue Service ("IRS"). Our expenses relating to the 401(k) Plan were $2.1 million, $1.8 million and $1.4 million for the years 2012, 2011 and 2010, respectively.

13. Income Taxes

Income Tax Expense

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

	Year Ended December 31,		
	2012	2011	2010
Current	$(40,562)	$29,682	$20,167
Deferred	88,109	61,835	(8,266)
	$ 47,547	$91,517	$11,901

Effective Tax Rate Reconciliation

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

	Year Ended December 31,					
	2012		2011		2010	
Income tax expense at the federal statutory rate	$41,836	35.0%	$92,517	35.0%	$ 45,427	35.0%
Valuation allowance	—	—	—	—	(31,985)	(24.6)
Domestic production activities adjustment	4,256	3.5	(1,823)	(0.7)	(2,623)	(2.0)
State income taxes	750	0.6	603	0.2	32	—
Other	705	0.7	220	0.1	1,050	0.8
	$47,547	39.8%	$91,517	34.6%	$ 11,901	9.2%

Our effective tax rate for the year 2012 differed from the federal statutory rate primarily as a result of the recapture of deductions for qualified domestic production activities under Section 199 of the IRC as a function of loss carrybacks to prior years and the impact of state income taxes. Our effective tax rate for the year 2011 differed from the federal statutory rate primarily as a result of the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the IRC. Our effective tax rate for the year 2010 differed from the federal statutory rate primarily as a result of a reduction in our valuation allowance against our deferred tax assets and the Section 199 deduction described above. Taxable income in 2010 allowed us to reverse all of the previously recorded valuation allowance.

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,	
	2012	2011
Deferred tax liabilities:		
Property and equipment	$186,599	$63,328
Other	4,822	4,707
Total deferred tax liabilities	191,421	68,035
Deferred tax assets:		
Minimum tax credit	22,314	—
Federal net operating losses	12,389	—
State net operating losses	5,057	4,626
Derivatives	3,312	1,096
Valuation allowance (state)	(4,674)	(4,626)
Accrued cash-based bonus	2,455	5,390
Stock-based compensation	4,256	3,971
Other	1,330	704
Total deferred tax assets	46,439	11,161
Net deferred tax liabilities	$144,982	$56,874

During 2012, we made payments primarily for federal and state income taxes of approximately $16.1 million. We received refunds related to prior years of $0.5 million. During 2011, we made payments primarily for federal and state income taxes of approximately $35.7 million. We received refunds related to prior years of $0.4 million.

During 2010, we received refunds of federal income taxes paid in prior years totaling $99.8 million, consisting primarily of carrybacks of net operating losses generated in 2009 and 2008 and made payments of $12.0 million for federal and state income taxes.

At December 31, 2012, we had a federal income tax receivable of $47.9 million. This amount is comprised principally of a net operating loss carryback from 2012 to 2010 of $29.1 million and a net operating loss carryback from 2012 to 2011 of $13.8 million. Additionally, federal estimated tax payments were deposited in 2012 of $5.0 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, 2012 (in thousands):

	Amount	Expiration Year
Federal net operating loss	$35,399	2032
State net operating losses	95,780	2017-2027
Minimum tax credit	22,314	Indefinite
General business credit	406	2027-2028

Valuation Allowance

As of December 31, 2012 and December 31, 2011, we had a valuation allowance related to Louisiana state net operating losses. 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.

Uncertain Tax Positions

The table below sets forth the reconciliation of the beginning and ending balances of the total amount of unrecognized tax benefits. There are no unrecognized benefits that would impact the effective tax rate if recognized. While amounts could change in the next 12 months, we do not anticipate it having a material impact on our financial statements. We recognize interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2012, we had zero accrued interest related to uncertain tax positions. During 2011, we recognized $0.3 million of income tax benefit for the reversal of accrued interest and penalties.

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

	December 31,	
	2012	2011
Balance at beginning of period	—	$ 3,558
(Decreases) related to prior-year tax positions	—	(3,558)
Balance at end of period	—	$ —

Years open to examination

The tax years from 2009 through 2012 remain open to examination by the tax jurisdictions to which we are subject.

14. Earnings Per Share

In accordance with the *Earnings Per Share* topic of the Codification, the Company's unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are deemed participating securities and are included in the computation of earnings per share under the two-class method.

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

	Year Ended December 31,		
	2012	2011	2010
Net income	$71,984	$172,817	$117,892
Less portion allocated to nonvested shares	983	3,211	1,178
Net income allocated to common shares	$71,001	$169,606	$116,714
Weighted average common shares outstanding	74,354	74,033	73,685
Basic and diluted earnings per common share	$ 0.95	$ 2.29	$ 1.58
Shares excluded due to being anti-dilutive	1,923	1,873	1,540

15. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2012	2011	2010
Cash paid for interest, net of interest capitalized of $13,274 in 2012, $9,877 in 2011 and $5,395 in 2010	$46,247	$39,772	$36,362
Cash paid for income taxes	16,056	35,655	12,000
Cash refunds received for income taxes	479	379	99,828
Cash paid for share-based compensation (1)	1,531	1,062	452
Cash tax benefit related to share-based compensation (2)	5,962	3,125	6,871

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

(2) The cash tax benefit for share-based compensation is attributable to tax deductions for vested restricted shares, vested RSUs, dividends paid on unvested restricted stock and dividend equivalents paid on RSUs. Tax refunds were received in 2010 that included carrybacks of net operating losses for the years 2009 and 2008 to prior years, therefore the tax cash benefits from share-based compensation in those years was determined to be received in 2010. In addition, refunds related to the carryback of 2008 net operating loss to prior years were also received in 2009. As refunds could not be specifically determined as to which related to share-based compensation, it was assumed these cash flows were received in 2010 as most refunds were received in that year.

16. Commitments

We have operating lease agreements for office space and office equipment. The lease for the majority of our office space terminates in December 2022. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2012 are as follows (in millions): 2013 – $1.2; 2014 – $1.3; 2015 – $1.3; thereafter – $9.3.

Total rent expense was approximately $1.7 million, $1.9 million and $2.0 million during 2012, 2011 and 2010, respectively.

Pursuant to the Purchase and Sale Agreement with Total E&P, we are required to fulfill security requirements related to ARO for certain properties through bonds or making payments to an escrow account or a combination. As of December 31, 2012, we were in compliance with the security amount requirement of $46.0 million. Additional security requirements are $9.0 million in 2013, $9.0 million in 2014, $9.0 million in 2015, $6.0 million in 2016 and $24.0 million in the 2017 to 2023 time period to a total security requirement of $103.0 million by 2023.

Pursuant to the Purchase and Sale agreement with Shell related to ARO for certain properties, we have bonds that are subject to re-appraisal in the 2015. The current security requirement of $74.0 million could be increased up to $94.0 million depending on certain conditions and circumstances.

We have no drilling rig commitments with a term that exceeded one year as of December 31, 2012 and our drilling rig commitments meet the criteria of an operating lease. Future payments of all drilling rig commitments as of December 31, 2012 were $36.5 million in 2013 and none beyond 2013.

17. Related Parties

During 2012, 2011 and 2010, there were certain transactions between us and companies our majority shareholder either controlled or had an ownership interest in. In addition, there were transactions with a company that employs the spouse of our majority shareholder. Our majority shareholder owns a certain aircraft that the Company used and reimbursed him for such use and for his use. Airplane services were charged to us at rates that were either equal to or below rates charged by non-related, third-party companies. Airplane services transactions were approximately $1.0 million, $1.1 million and $0.9 million for the years 2012, 2011 and 2010, respectively. Our majority shareholder has ownership interests in certain wells operated by us (such ownership interests pre-date our initial public offering). Revenues are disbursed and expenses are collected in accordance with ownership interest. Proportionate insurance premiums were paid to us and proportionate collections of insurance reimbursements attributable to damage on certain wells were disbursed. W&T hired the services of a directional drilling services company, in which our majority shareholder owns a minority ownership interest and serves on its board of directors, and W&T paid $0.7 million for drilling related services during 2012. A company that provides logistics services to W&T employs the spouse of our majority shareholder. The spouse received commissions partially based on services rendered to W&T which totaled less than $0.1 million per year for 2012 and 2011. All these transactions were determined to be priced at competitive rates and were reviewed by the Audit Committee for compliance with our policies and procedures.

18. Contingencies

Federal Grand Jury Investigation. The United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the U.S. Environmental Protection Agency (the "EPA") conducted a federal grand jury investigation beginning in late 2010 of environmental compliance matters relating to surface discharges and reporting on four of our offshore platforms in the Gulf of Mexico in 2009. In December 2012, an agreement was reached that resolves these environmental violations and the agreement was approved by the federal district court in January 2013. Under the agreement, the Company on January 3, 2013 (i) pled guilty to one felony count under the Clean Water Act for altering monthly produced water discharge samples for the Ewing Banks 910 platform in 2009 and one misdemeanor count under the Clean Water Act for negligently discharging a small amount of oil from the same platform in November 2009 and (ii) paid a $0.7 million fine and $0.3 million for community service and (iii) entered into an environmental compliance program subject to a third-party audit. Under the agreement, the Company was placed on a three-year term of probation. The probation terms require that the Company: a) commit no further criminal violations, b) pay in full amounts pursuant to the agreement, c) comply with an Environmental Compliance Plan during the probation period, and d) take no adverse action against personnel who cooperated in the investigation. The agreement further stipulates that the Government will not seek any further criminal charges against the Company in this matter.

Cameron Parish Louisiana Claim. Since 2009, certain Cameron Parish landowners have filed suits in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and Tracy W. Krohn as well as several other defendants unrelated to us. In their lawsuits, plaintiffs alleged that property they own has been contaminated or otherwise damaged by the defendants' oil and gas exploration and production activities and they are seeking compensatory and punitive damages. During 2012, we settled claims with certain landowners and paid $10.0 million. We assessed the remaining claims to be probable and have accrued $1.3 million in our contingent liabilities as of December 31, 2012. However, we cannot state with certainty that our estimates of additional exposure are accurate concerning this matter.

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

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

The complaint alleges that environmental violations at three of the Company's operated production platforms in the Gulf of Mexico violate the federal offshore lease provisions so that the Company, among other things, wrongfully retained benefits under the applicable leases. The alleged environmental violations include allegations of discharges of relatively small amounts of oil into the Gulf of Mexico, the failure to report and record such discharges, and falsification of certain produced water samples and related reports required under federal law. The events are alleged to have occurred in 2009. These are largely the same allegations involved in the federal grand jury investigation described above. We have filed a motion to dismiss the claim. The plaintiff dismissed his claims against the three other working interest owners after they filed motions to dismiss. The plaintiff conceded that certain of his claims should be dismissed in his reply to the Company's motion to dismiss. The motion remains pending before the court.

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

Insurance Claims. During the fourth quarter of 2012, underwriters of W&T's excess liability policies (Indemnity Insurance Company of North America, New York Marine & General Insurance Company, Navigators Insurance Company; XL Specialty Insurance Company and Liberty Mutual Insurance Co.) filed declaratory judgment actions in the United States District Court for the Southern District of Texas seeking a determination that such policies do not cover removal of wreck and debris claims arising from Hurricane Ike that occurred in 2008. The court consolidated the various suits filed by underwriters. W&T has not yet filed any claim under such excess policies, but W&T anticipates that such claims may reach $50.0 million in aggregate. In January 2013, the Company filed a motion for summary judgment seeking the court's determination that such excess policies do in fact provide coverage for such removal of wreck and debris claims. The motion for summary judgment is pending. If successful, we expect to receive reimbursement for these costs once costs have been incurred and claims submitted. Costs that have been incurred in connection with potential claims have been recorded in *Oil and natural gas properties and equipment* on the Consolidated Balance Sheet. Any recoveries from claims made on these policies related to this issue will be recorded as reductions in this line item.

Royalties. In 2009, the Company recognized $5.3 million in allowable reductions of cash payments for royalties owed to the Office of Natural Resources Revenue (the "ONRR") for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited the calculations and support related to this usage fee, and in the third quarter of 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue of $4.7 million in the third quarter of 2010 to reflect this disallowance; however, we disagree with the position taken by the ONRR and we are pursuing our claim to resolve the matter.

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

Contingent Liability Recorded. We recognized expenses related to accrued and settled claims, complaints and fines of $9.3 million, $1.7 million and $0.7 million for the years 2012, 2011 and 2010, respectively. These expenses are reported in *General and administrative expenses* on the statement of income and reflect the items noted above and other various claims and complaints. As of December 31, 2012 and 2011, we have recorded a liability of $1.3 million and $2.0 million, respectively, which is included in *Accrued liabilities* on the balance sheet, for the loss contingencies matters that include the events described above and other minor environmental and litigation matters which we are addressing in the normal course of business.

19. Selected Quarterly Financial Data – UNAUDITED

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2012				
Revenues	$235,886	$215,513	$185,946	$237,146
Operating income	15,913	99,100	7,560	46,737
Net income (loss)	3,218	53,567	(1,471)	16,670
Basic and diluted earnings (loss) per common share (1)	0.04	0.70	(0.02)	0.21
Year Ended December 31, 2011				
Revenues	$210,855	$252,922	$245,371	$261,899
Operating income	37,548	115,643	95,333	80,936
Net income	18,649	55,175	52,928	46,065
Basic and diluted earnings per common share (1)	0.25	0.73	0.70	0.61

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

20. Supplemental Guarantor Information

Our payment obligations under the Company's outstanding Senior Notes and the Credit Agreement (see Note 7) are fully and unconditionally guaranteed by certain of our wholly-owned subsidiaries, Energy VI, which includes the operations of the acquisitions closed in 2010 as described in Note 2, and W&T Energy VII, LLC, which does not have any active operations (together, the "Guarantor Subsidiaries"). Guarantees of the Senior Notes will be released under certain circumstances, including:

(1) in connection with any sale or other disposition of all or substantially all of the assets of a Guarantor Subsidiary (including by way of merger or consolidation) to a person that is not (either before or after giving

effect to such transaction) the Company or a Restricted Subsidiary (as such term is defined in the indenture governing the Senior Notes) of the Company, if the sale or other disposition does not violate the "Asset Sales" provisions of the indenture;

(2) in connection with any sale or other disposition of the capital stock of such Guarantor Subsidiary to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the "Asset Sales" provisions of the indenture and the Guarantor Subsidiary ceases to be a subsidiary of the Company as a result of such sales or disposition;

(3) if such Guarantor Subsidiary is a Restricted Subsidiary and the Company designates such Guarantor Subsidiary as an Unrestricted Subsidiary in accordance with the applicable provisions of the indenture;

(4) upon Legal Defeasance or Covenant Defeasance (as such terms are defined in the indenture) or upon satisfaction and discharge of the indenture;

(5) upon the liquidation or dissolution of such Guarantor Subsidiary, provided no event of default has occurred and is continuing; or

(6) at such time as such Guarantor Subsidiary is no longer required to be a Guarantor Subsidiary of the Senior Notes as described in the indenture, provided no event of default has occurred and is continuing.

The following condensed consolidating financial information presents the financial condition, results of operations and cash flows of W&T Offshore, Inc. (the "Parent Company") and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company's results on a consolidated basis.

Condensed Consolidating Balance Sheet as of December 31, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 12,245	$ —	$ —	$ 12,245
Receivables:				
Oil and natural gas sales	80,729	17,004	—	97,733
Joint interest and other	56,439	—	—	56,439
Income taxes	163,750	—	(115,866)	47,884
Total receivables	300,918	17,004	(115,866)	202,056
Deferred income taxes	267	—	—	267
Prepaid expenses and other assets	25,555	—	—	25,555
Total current assets	338,985	17,004	(115,866)	240,123
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,356,529	337,981	—	6,694,510
Furniture, fixtures and other	21,786	—	—	21,786
Total property and equipment	6,378,315	337,981	—	6,716,296
Less accumulated depreciation, depletion and amortization	4,461,886	193,955	—	4,655,841
Net property and equipment	1,916,429	144,026	—	2,060,455
Restricted deposits for asset retirement obligations	28,466	—	—	28,466
Deferred income taxes	—	13,509	(13,509)	—
Other assets	442,540	393,499	(816,096)	19,943
Total assets	$2,726,420	$568,038	$(945,471)	$2,348,987
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 123,792	$ 93	$ —	$ 123,885
Undistributed oil and natural gas proceeds	36,791	282	—	37,073
Asset retirement obligations	92,595	—	35	92,630
Accrued liabilities	20,755	—	—	20,755
Income taxes	—	116,132	(115,866)	266
Total current liabilities	273,933	116,507	(115,831)	274,609
Long-term debt	1,087,611	—	—	1,087,611
Asset retirement obligations, less current portion	262,524	28,934	(35)	291,423
Deferred income taxes	158,758	—	(13,509)	145,249
Other liabilities	402,407	—	(393,499)	8,908
Commitments and contingencies				
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	396,186	231,759	(231,759)	396,186
Retained earnings	169,167	190,838	(190,838)	169,167
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	541,187	422,597	(422,597)	541,187
Total liabilities and shareholders' equity	$2,726,420	$568,038	$(945,471)	$2,348,987

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

Condensed Consolidating Balance Sheet as of December 31, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 4,512	$ —	$ —	$ 4,512
Receivables:				
Oil and natural gas sales	78,131	20,419	—	98,550
Joint interest and other	25,089	—	—	25,089
Insurance	715	—	—	715
Income taxes	74,183	—	(74,183)	—
Total receivables	178,118	20,419	(74,183)	124,354
Deferred income taxes	2,007	—	—	2,007
Prepaid expenses and other assets	30,315	—	—	30,315
Total current assets	214,952	20,419	(74,183)	161,188
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,689,535	269,481	—	5,959,016
Furniture, fixtures and other	19,500	—	—	19,500
Total property and equipment	5,709,035	269,481	—	5,978,516
Less accumulated depreciation, depletion and amortization	4,208,825	111,585	—	4,320,410
Net property and equipment	1,500,210	157,896	—	1,658,106
Restricted deposits for asset retirement obligations	33,462	—	—	33,462
Deferred income taxes	—	17,637	(17,637)	—
Other assets	372,572	275,181	(631,584)	16,169
Total assets	$2,121,196	$471,133	$(723,404)	$1,868,925
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 73,333	$ 2,538	$ —	$ 75,871
Undistributed oil and natural gas proceeds	33,391	341	—	33,732
Asset retirement obligations	138,185	—	—	138,185
Accrued liabilities	29,705	—	—	29,705
Income taxes	—	84,575	(74,183)	10,392
Total current liabilities	274,614	87,454	(74,183)	287,885
Long-term debt	717,000	—	—	717,000
Asset retirement obligations, less current portion	228,419	27,276	—	255,695
Deferred income taxes	76,518	—	(17,637)	58,881
Other liabilities	280,071	—	(275,181)	4,890
Commitments and contingencies				
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	386,920	231,759	(231,759)	386,920
Retained earnings	181,820	124,644	(124,644)	181,820
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	544,574	356,403	(356,403)	544,574
Total liabilities and shareholders' equity	$2,121,196	$471,133	$(723,404)	$1,868,925

Condensed Consolidating Statement of Income for the Twelve Months Ended December 31, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$659,203	$215,288	$ —	$874,491
Operating costs and expenses:				
Lease operating expenses	209,581	22,679	—	232,260
Production taxes	5,840	—	—	5,840
Gathering and transportation	11,703	3,175	—	14,878
Depreciation, depletion and amortization	253,807	82,370	—	336,177
Asset retirement obligation accretion	17,463	2,592	—	20,055
General and administrative expenses	79,424	2,593	—	82,017
Derivative loss	13,954	—	—	13,954
Total costs and expenses	591,772	113,409	—	705,181
Operating income	67,431	101,879	—	169,310
Earnings of affiliates	66,195	—	(66,195)	—
Interest expense:				
Incurred	63,268	—	—	63,268
Capitalized	(13,274)	—	—	(13,274)
Other income	215	—	—	215
Income before income tax expense	83,847	101,879	(66,195)	119,531
Income tax expense	11,863	35,684	—	47,547
Net income	$ 71,984	$ 66,195	$(66,195)	$ 71,984

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

Condensed Consolidating Statement of Income for the Twelve Months Ended December 31, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$697,899	$273,148	$ —	$971,047
Operating costs and expenses:				
Lease operating expenses	182,165	37,041	—	219,206
Production taxes	4,275	—	—	4,275
Gathering and transportation	12,676	4,244	—	16,920
Depreciation, depletion and amortization	214,740	84,275	—	299,015
Asset retirement obligation accretion	26,947	2,824	—	29,771
General and administrative expenses	71,714	2,582	—	74,296
Derivative gain	(1,896)	—	—	(1,896)
Total costs and expenses	510,621	130,966	—	641,587
Operating income	187,278	142,182	—	329,460
Earnings of affiliates	92,533	—	(92,533)	—
Interest expense:				
Incurred	52,393	—	—	52,393
Capitalized	(9,877)	—	—	(9,877)
Loss on extinguishment of debt	22,694	—	—	22,694
Other income	84	—	—	84
Income before income tax expense	214,685	142,182	(92,533)	264,334
Income tax expense	41,868	49,649	—	91,517
Net income	$172,817	$ 92,533	$(92,533)	$172,817

Condensed Consolidating Statement of Income for the Twelve Months Ended December 31, 2010

	Parent Company	Guarantor Subsidiaries (1)	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$608,600	$97,183	$ —	$705,783
Operating costs and expenses:				
Lease operating expenses	152,534	17,136	—	169,670
Production taxes	1,194	—	—	1,194
Gathering and transportation	15,338	1,146	—	16,484
Depreciation, depletion and amortization	241,105	27,310	—	268,415
Asset retirement obligation accretion	25,122	563	—	25,685
General and administrative expenses	51,662	1,628	—	53,290
Derivative loss	4,256	—	—	4,256
Total costs and expenses	491,211	47,783	—	538,994
Operating income	117,389	49,400	—	166,789
Earnings of affiliates	32,110	—	(32,110)	—
Interest expense:				
Incurred	43,101	—	—	43,101
Capitalized	(5,395)	—	—	(5,395)
Other income	710	—	—	710
Income before income tax expense (benefit)	112,503	49,400	(32,110)	129,793
Income tax expense (benefit)	(5,389)	17,290	—	11,901
Net income	$117,892	$32,110	$(32,110)	$117,892

(1) Began operations on May 1, 2010.

Condensed Consolidating Statement of Cash Flows for the Twelve Months Ended December 31, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 71,984	$ 66,195	$ (66,195)	$ 71,984
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	271,270	84,962	—	356,232
Amortization of debt issuance costs and premium	2,575	—	—	2,575
Share-based compensation	12,398	—	—	12,398
Derivative loss	13,954	—	—	13,954
Cash payments on derivative settlements	(7,664)	—	—	(7,664)
Deferred income taxes	83,981	4,128	—	88,109
Earnings of affiliates	(66,195)	—	66,195	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	(2,597)	3,415	—	818
Joint interest and other receivables	(31,399)	—	—	(31,399)
Insurance receivables	2,576	—	—	2,576
Income taxes	(89,568)	31,557	—	(58,011)
Prepaid expenses and other assets	7,442	(118,320)	118,318	7,440
Asset retirement obligations	(112,199)	(628)	—	(112,827)
Accounts payable and accrued liabilities	40,530	(2,504)	—	38,026
Other liabilities	119,244	—	(118,318)	926
Net cash provided by operating activities	316,332	68,805	—	385,137
Investing activities:				
Acquisition of property interest in oil and natural gas properties	(205,550)	—	—	(205,550)
Investment in oil and natural gas properties and equipment	(410,508)	(68,805)	—	(479,313)
Proceeds from sales of oil and natural gas properties and equipment	30,453	—	—	30,453
Purchases of furniture, fixtures, misc. sales and other	(3,031)	—	—	(3,031)
Net cash used in investing activities	(588,636)	(68,805)	—	(657,441)
Financing activities:				
Issuance of 8.50% Senior Notes	318,000	—	—	318,000
Borrowings of long-term debt – revolving bank credit facility	732,000	—	—	732,000
Repayments of long-term debt – revolving bank credit facility	(679,000)	—	—	(679,000)
Debt issuance costs	(8,510)	—	—	(8,510)
Dividends to shareholders	(82,832)	—	—	(82,832)
Other	379	—	—	379
Net cash provided by financing activities	280,037	—	—	280,037
Increase in cash and cash equivalents	7,733	—	—	7,733
Cash and cash equivalents, beginning of period	4,512	—	—	4,512
Cash and cash equivalents, end of period	$ 12,245	$ —	$ —	$ 12,245

Condensed Consolidating Statement of Cash Flows for the Twelve Months Ended December 31, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 172,817	$ 92,533	$ (92,533)	$ 172,817
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	241,687	87,099	—	328,786
Amortization of debt issuance costs	2,010	—	—	2,010
Loss on extinguishment of debt	22,694	—	—	22,694
Share-based compensation	9,710	—	—	9,710
Derivative gain	(1,896)	—	—	(1,896)
Cash payments on derivative settlements	(9,873)	—	—	(9,873)
Deferred income taxes	76,717	(14,882)	—	61,835
Earnings of affiliates	(92,533)	—	92,533	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	(27,709)	9,070	—	(18,639)
Joint interest and other receivables	375	—	—	375
Insurance receivables	20,771	—	—	20,771
Income taxes	(71,655)	64,531	—	(7,124)
Prepaid expenses and other assets	(8,003)	(228,020)	228,214	(7,809)
Asset retirement obligations	(59,958)	—	—	(59,958)
Accounts payable and accrued liabilities	8,589	(514)	(194)	7,881
Other liabilities	227,918	—	(228,020)	(102)
Net cash provided by operating activities	511,661	9,817		521,478
Investing activities:				
Acquisition of property interest in oil and natural gas properties	(437,247)	—	—	(437,247)
Investment in oil and natural gas properties and equipment	(277,147)	(4,632)	—	(281,779)
Investment in subsidiary	5,185	—	(5,185)	—
Purchases of furniture, fixtures, misc. sales and other	(3,645)	—	—	(3,645)
Net cash used in investing activities	(712,854)	(4,632)	(5,185)	(722,671)
Financing activities:				
Issuance of 8.50% Senior Notes	600,000	—	—	600,000
Repurchase of 8.25% Senior Notes	(450,000)	—	—	(450,000)
Borrowings of long-term debt – revolving bank credit facility	623,000	—	—	623,000
Repayments of long-term debt – revolving bank credit facility	(506,000)	—	—	(506,000)
Repurchase premium and debt issuance costs	(32,288)	—	—	(32,288)
Dividends to shareholders	(58,756)	—	—	(58,756)
Other	1,094	—	—	1,094
Investment from parent	—	(5,185)	5,185	—
Net cash provided by (used in) financing activities	177,050	(5,185)	5,185	177,050
Decrease in cash and cash equivalents	(24,143)	—	—	(24,143)
Cash and cash equivalents, beginning of period	28,655	—	—	28,655
Cash and cash equivalents, end of period	$ 4,512	$ —	$ —	$ 4,512

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

Condensed Consolidating Statement of Cash Flows for the Twelve Months Ended December 31, 2010

	Parent Company	Guarantor Subsidiaries (1)	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 117,892	$ 32,110	$ (32,110)	$ 117,892
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	266,227	27,873	—	294,100
Amortization of debt issuance costs	1,338	—	—	1,338
Share-based compensation	5,533	—	—	5,533
Derivative loss	4,256	—	—	4,256
Cash payments on derivative settlements	874	—	—	874
Deferred income taxes	(5,511)	(2,755)	—	(8,266)
Earnings of affiliates	(32,110)	—	32,110	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	4,556	(29,489)	—	(24,933)
Joint interest and other receivables	25,897	—	—	25,897
Insurance receivables	54,873	—	—	54,873
Income taxes	84,023	20,044	—	104,067
Prepaid expenses and other assets	4,536	(47,160)	47,160	4,536
Asset retirement obligations	(87,166)	—	—	(87,166)
Accounts payable and accrued liabilities	(35,278)	3,393	—	(31,885)
Other liabilities	50,816	—	(47,160)	3,656
Net cash provided by operating activities	460,756	4,016	—	464,772
Investing activities:				
Acquisition of property interest in oil and natural gas properties	—	(236,944)	—	(236,944)
Investment in oil and natural gas properties and equipment	(174,693)	(4,016)	—	(178,709)
Proceeds from sales of oil and natural gas properties and equipment	1,420	—	—	1,420
Investment in subsidiary	(236,944)	—	236,944	—
Purchases of furniture, fixtures and other	(760)	—	—	(760)
Net cash used in investing activities	(410,977)	(240,960)	236,944	(414,993)
Financing activities:				
Borrowings of revolving bank credit facility	627,500	—	—	627,500
Repayments of revolving bank credit facility	(627,500)	—	—	(627,500)
Dividends to shareholders	(59,609)	—	—	(59,609)
Other	298	—	—	298
Investment from parent	—	236,944	(236,944)	—
Net cash provided by (used in) financing activities	(59,311)	236,944	(236,944)	(59,311)
Decrease in cash and cash equivalents	(9,532)	—	—	(9,532)
Cash and cash equivalents, beginning of period	38,187	—	—	38,187
Cash and cash equivalents, end of period	$ 28,655	$ —	$ —	$ 28,655

(1) Began operations on May 1, 2010.

21. Supplemental Oil and Gas Disclosures – UNAUDITED

Geographic Area of Operation

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

Capitalized Costs

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

	December 31, 2012	2011	2010
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 6,551.5	$ 5,775.4	$ 5,130.9
Unproved oil and natural gas properties and equipment	143.0	183.6	94.7
Accumulated depreciation, depletion and amortization related to oil, NGLs and natural gas activities	(4,640.8)	(4,307.1)	(4,009.9)
Net capitalized costs related to producing activities	$ 2,053.7	$ 1,651.9	$ 1,215.7

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, 2012, by the year in which the costs were incurred (in millions):

	Total	2012	2011	2010	Prior to 2010
Costs excluded by year incurred:					
Acquisition costs	$ 99.8	$13.1	$67.4	$ —	$19.3
Capitalized interest not subject to amortization	23.7	9.1	6.1	2.1	6.4
Total costs not subject to amortization	$123.5	$22.2	$73.5	$2.1	$25.7

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

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

	Year Ended December 31,		
	2012	2011	2010
Costs incurred (1):			
Proved property acquisitions	$239.8	$369.9	$277.3
Exploration (2) (3)	151.3	92.7	70.8
Development	363.7	203.7	158.3
Unproved property acquisitions (4)	26.5	95.1	19.7
Total costs incurred in oil and gas property acquisition, exploration and development activities	$781.3	$761.4	$526.1

(1) Includes additions (reductions) to our ARO of $86.9 million, $32.8 million and $106.1 million during 2012, 2011 and 2010, respectively, associated with acquisitions, liabilities incurred and revisions of estimates. Refer to Note 5.
(2) Includes seismic costs of $6.2 million, $8.0 million and $5.8 million incurred during 2012, 2011 and 2010, respectively.
(3) Includes geological and geophysical costs charged to expense of $6.2 million, $6.8 million and $4.3 million during 2012, 2011 and 2010, respectively.
(4) The amounts for 2012, 2011 and 2010 include capitalized interest associated with properties classified as unproved at December 31, 2012, 2011 and 2010, respectively.

Depreciation, depletion, amortization and accretion expense

The following table presents our depreciation, depletion, amortization and accretion expense per million cubic feet equivalent ("Mcfe") of products sold.

	Year Ended December 31,		
	2012	2011	2010
Depreciation, depletion, amortization and accretion per Mcfe	$3.47	$3.24	$3.38

Oil and Natural Gas Reserve Information

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve information represent estimates only and are inherently imprecise and may be subject to substantial revisions as additional information such as reservoir performance, additional drilling, technological advancements and other factors become available. Decreases in the prices of oil, NGLs and natural gas could have an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow. We are not the operator with respect to approximately 14% 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, NGLs and natural gas reserves. All of the reserves are located in the Unites States and the majority of the reserves are located in the Gulf of Mexico. These reserve estimates exclude insignificant royalties and interests owned by the Company due to the unavailability of such information.

				Total Equivalent Reserves	
	Oil (MMBbls) (1)	NGLs (MMBbls) (1)	Natural Gas (Bcf) (1)	Oil Equivalent (MMBoe) (2)	Natural Gas Equivalent (Bcfe) (2)
Proved reserves as of December 31, 2009	31.2	3.0	165.8	61.8	371.0
Revisions of previous estimates (3)	(0.2)	1.2	14.6	3.4	20.2
Extensions and discoveries (4)	1.2	0.5	19.1	4.9	29.2
Purchase of minerals in place (5)	7.7	0.7	101.5	25.3	152.0
Production	(5.9)	(1.2)	(44.7)	(14.5)	(87.0)
Proved reserves as of December 31, 2010	34.0	4.2	256.3	80.9	485.4
Revisions of previous estimates (6)	0.8	5.5	13.5	8.6	51.1
Extensions and discoveries (7)	2.0	0.4	17.7	5.3	32.0
Purchase of minerals in place (8)	20.7	8.9	55.9	39.0	234.1
Production	(6.1)	(1.9)	(53.7)	(16.9)	(101.5)
Proved reserves as of December 31, 2011	51.4	17.1	289.7	116.9	701.1
Revisions of previous estimates (9)	(1.1)	(2.6)	(4.8)	(4.6)	(27.5)
Extensions and discoveries (10)	8.2	2.6	29.6	15.7	94.5
Purchase of minerals in place (11)	2.5	0.2	25.5	7.0	42.0
Sales of reserves (12)	(0.2)	—	(1.1)	(0.4)	(2.2)
Production	(6.0)	(2.1)	(53.8)	(17.1)	(102.8)
Proved reserves as of December 31, 2012	54.8	15.2	285.1	117.5	705.1
Year-end proved developed reserves:					
2012	35.3	11.0	243.5	86.9	521.2
2011	23.4	11.0	251.4	76.4	458.2
2010	23.6	3.4	229.1	65.2	391.3
Year-end proved undeveloped reserves:					
2012	19.5	4.2	41.6	30.6	183.9
2011	28.0	6.1	38.3	40.5	242.9
2010	10.4	0.8	27.2	15.7	94.1

(1) Estimated reserves as of December 31, 2012, 2011, 2010 and 2009 are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for those years in accordance with current definitions and guidelines set forth by the SEC and the FASB.

(2) The conversion to barrels of oil equivalent and cubic feet equivalent were determined using the energy-equivalent ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs (totals may not compute due to rounding). The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for oil, NGLs and natural gas may differ significantly.

(3) Includes revisions due to price of 17.5 Bcfe.

(4) Includes discoveries of 21.9 Bcfe primarily in the Main Pass 108, Main Pass 98 and Main Pass 283 fields and extensions of 7.2 Bcfe primarily in the Main Pass 283 field.

(5) Primarily due to the acquisition of the Total Properties and the Tahoe Properties.

(6) Includes revision of 6.3 Bcfe due to an increase in average prices; 16.5 Bcfe for a change in NGLs marketing arrangements; 11.3 Bcfe increase due to additional compression at our Tahoe field that increases production and ultimate recoveries; and 10.6 Bcfe at our Fairway field for revisions to reserve estimates from the acquisition date to year end.
(7) Includes discoveries of 13.9 Bcfe at our Main Pass 98 field and 8.0 Bcfe at our Ship Shoal 349/359 field and extensions of 3.7 Bcfe at our Main Pass 108 field.
(8) Primarily due to the acquisition of the Yellow Rose Properties and the Fairway Properties.
(9) Includes downward revisions due to price of 8.0 Bcfe and negative performance revisions of 17.9 Bcfe at our Yellow Rose Properties.
(10) Includes extensions and discoveries of 69.5 Bcfe at our Yellow Rose Properties and extensions and discoveries of 16.2 Bcfe at our High Island 22 field.
(11) Due to the acquisition of the Newfield Properties.
(12) Due to the sale of our interest in the South Timbalier 41 field.

Volume measurements:

Mcf – thousand cubic feet	Bbl – barrel
Bcf – billion cubic feet	MMBbls – million barrels for crude oil, condensate or NGLs
Bcfe – billion cubic feet equivalent	MMBoe – million barrels of oil equivalent

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 December 31, 2012, 2011, 2010 and 2009. All prices are adjusted by lease for quality, transportation fees, energy content and regional price differentials. Due to the lack of a benchmark price for NGLs, a ratio is computed for each field of the NGLs realized price compared to the oil realized price. Then, this ratio is applied to the oil price using FASB/SEC guidance. The average commodity prices weighted by field production related to the proved reserves are as follows:

	December 31,			
	2012	2011	2010	2009
Oil – per barrel	$98.13	$97.36	$76.28	$55.87
NGLs – per barrel	47.30	51.30	44.92	33.36
Natural gas – per Mcf	2.77	4.11	4.57	3.80

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

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of our oil and natural gas reserves. These estimates reflect proved reserves only and ignore, among other things, future changes in prices and costs, revenues that could result from probable reserves which could become proved reserves in 2013 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,		
	2012	2011	2010
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 6,888,431	$ 7,077,206	$ 3,953,655
Future costs:			
Production	(1,858,282)	(1,862,488)	(1,011,552)
Development	(655,406)	(543,017)	(243,570)
Dismantlement and abandonment	(508,051)	(513,620)	(520,490)
Income taxes	(1,002,127)	(1,126,573)	(495,696)
Future net cash inflows before 10% discount	2,864,565	3,031,508	1,682,347
10% annual discount factor	(1,018,188)	(1,025,131)	(503,275)
	$ 1,846,377	$ 2,006,377	$ 1,179,072

	Year Ended December 31,		
	2012	2011	2010
Changes in Standardized Measure			
Standardized measure, beginning of year	$2,006,377	$1,179,072	$ 660,396
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(620,437)	(729,574)	(521,551)
Net changes in price, net of future production costs	(224,260)	634,174	367,575
Extensions and discoveries, net of future production and development costs	181,870	219,924	143,612
Changes in estimated future development costs	(103,320)	(4,572)	(59,124)
Previously estimated development costs incurred	332,939	173,911	97,188
Revisions of quantity estimates	(128,075)	204,988	94,735
Accretion of discount	231,144	135,791	68,862
Net change in income taxes	99,684	(398,204)	(221,226)
Purchases of reserves in-place	270,168	483,286	624,302
Sales of reserves in-place	(16,105)	—	—
Changes in production rates due to timing and other	(183,608)	107,581	(75,697)
Net increase (decrease) in standardized measure	(160,000)	827,305	518,676
Standardized measure, end of year	$1,846,377	$2,006,377	$1,179,072

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, 2012 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, 2012, is set forth in "*Management's Report on Internal Control over Financial Reporting*" included in Part II, Item 8 of this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2012, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included in Part II, Item 8 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

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

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

Item 11. ***Executive Compensation***

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

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

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

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

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

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

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

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

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

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

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

2. Exhibits:

Exhibit Number	Description
2.1	Purchase and Sale Agreement, effective January 1, 2010, between Total E&P USA Inc. and W&T Offshore, Inc. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, filed on May 3, 2010 (File No. 001-32414))
2.2	Asset Purchase Agreement, dated November 3, 2010, between Shell Offshore, Inc., as Seller, and W&T Offshore, Inc. and W&T Energy VI, LLC, as Purchasers. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, filed November 9, 2010 (File No. 001-32414))
2.3	Purchase and Sale Agreement, dated April 25, 2011, between Opal Resources, LLC, Opal Resources Operating Company LLC, as Sellers, and W&T Offshore, Inc. (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed May 13, 2011 (File No. 001-32414))
2.4	Purchase and Sale Agreement, dated September 17, 2012, between Newfield Exploration Company, Newfield Exploration Gulf Coast LLC, as Sellers, and W&T Offshore, Inc. (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed October 12, 2012 (File No. 001-32414))
2.5	First Amendment to Purchase and Sale Agreement, dated October 5, 2012, between Newfield Exploration Company, Newfield Exploration Gulf Coast LLC, as Sellers, and W&T Offshore, Inc. (Incorporated by reference to Exhibit 2.2 of the Company's Current Report on Form 8-K, filed October 12, 2012 (File No. 001-32414))
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed February 24, 2006 (File No. 001-32414))
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
3.3	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q, filed July 31, 2012 (File No. 001-32414))
4.1	Specimen Common Stock Certificate. (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
4.2	Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))
4.3	First Supplemental Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))

Exhibit Number	Description
4.4	Form of 8.50% Senior Notes due 2019. (Incorporated by reference to Exhibit 4.3 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))
4.5	Registration Rights Agreement, dated October 24, 2012, by and among W&T Offshore, Inc., the Guarantors named therein and Morgan Stanley & Co. LLC, as representative of the Initial Purchasers. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed October 25, 2012 (File No. 001-32414))
10.1*	2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.11 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.2*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Stephen L. Schroeder, dated July 5, 2006. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed July 12, 2006 (File No. 001-32414))
10.3*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed February 26, 2007 (File No. 001-32414))
10.4*	Indemnification and Hold Harmless Agreement, dated September 24, 2008, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K, filed September 26, 2008 (File No. 001-32414))
10.5*	W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan. (Incorporated by reference from Appendix A to the Company's Definitive Proxy Statement on Schedule 14A, filed April 2, 2010 (File No. 001-32414))
10.6*	Form of Employment Agreement for Executive Officers other than the Chief Executive Officer. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 6, 2010 (File No. 001-32414))
10.7*	Form of the Executive Annual Incentive Award Agreement for Fiscal Year 2010. (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 (File No. 001-32414))
10.8*	Form of the Executive Restricted Stock Unit Agreement. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 (File No. 001-32414))
10.9*	Employment Agreement between W&T Offshore and Tracy W. Krohn dated as of November 1, 2010. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on November 5, 2010 (File No. 001-32414))
10.10*	Form of Employment Agreement by and between W&T Offshore, Inc. and Jesus G. Melendrez. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 19, 2011 (File No. 001-32414))
10.11*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Jesus G. Melendrez, dated as of January 17, 2010. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed January 19, 2011 (File No. 001-32414))
10.12	Fourth Amended and Restated Credit Agreement, dated May 5, 2011, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 6, 2011(File No. 001-32414))

Exhibit Number	Description
10.13*	Form of the Executive Annual Incentive Award Agreement for Fiscal Year 2011. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 001-32414))
10.14*	Form of Indemnification and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors. (Incorporated by reference to Exhibit 10.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 001-32414))
10.15	First Amendment to the Fourth Amended and Restated Credit Agreement, dated May 7, 2012, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 10, 2012 (File No. 001-32414))
10.16*	Form of Executive Restricted Stock Unit Agreement as of April 26, 2012. (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q, filed July 31, 2012 (File No. 001-32414))
10.17*	Form of Employment Agreement by and between W&T Offshore, Inc. and Thomas P. Murphy (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed August 6, 2010 (File No. 001-32414))
10.18*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Thomas P. Murphy, dated as of June 19, 2012. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed June 22, 2012 (File No. 001-32414))
10.19	Second Amendment to the Fourth Amended and Restated Credit Agreement, dated effective as of October 12, 2012, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed October 17, 2012 (File No. 001-32414))
12.1**	Ratio of Earnings to Fixed Charges
14.1	W&T Offshore, Inc. Code of Business Conduct and Ethics (as amended). (Incorporated by reference to Exhibit 14.1 of the Company's Current Report on Form 8-K, filed November 17, 2005)
21.1**	Subsidiaries of the Registrant.
23.1**	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
23.2**	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
31.1**	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2**	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer of W&T Offshore, Inc. pursuant to 18 U.S.C. § 1350.
99.1**	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Schema Document.
101.CAL**	XBRL Calculation Linkbase Document

Exhibit Number	Description
101.DEF**	XBRL Definition Linkbase Document.
101.LAB**	XBRL Label Linkbase Document.
101.PRE**	XBRL Presentation Linkbase Document.

* Management Contract or Compensatory Plan or Arrangement.

** Filed or furnished herewith.

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

Bcf. Billion cubic feet.

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

Boe. Barrel of oil equivalent.

BOEM. Bureau of Ocean Energy Management. The agency is responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

BOEMRE. Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service), was the federal agency that manages the nation's natural gas, oil and other mineral resources on the outer continental shelf. The BOEMRE was split into three separate entities: the Office of Natural Resources Revenue; the Bureau of Ocean Energy Management; and the Bureau of Safety and Environmental Enforcement.

BSEE. Bureau of Safety and Environmental Enforcement. The agency is responsible for enforcement of safety and environmental regulations. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

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

Deep shelf well. A well drilled on the outer continental shelf to subsurface depths greater than 15,000 feet and water depths of less than 500 feet.

Deepwater. Water depths greater than 500 feet in the Gulf of Mexico.

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

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

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

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

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

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

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

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

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

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

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

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet.

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

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

MMBoe. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

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

NGLs. Natural gas liquids. These are created during the processing of natural gas.

Oil. Crude oil and condensate.

OCS. Outer continental shelf

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

ONRR. Office of Natural Resources Revenue. The agency assumed the functions of the former Minerals Revenue Management Program, which had been renamed to the Bureau of Ocean Energy Management, Regulation and Enforcement.

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

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

Proved properties. Properties with proved reserves.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in this definition, "existing economic conditions" include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(22) of Regulation S-X.

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

PV-10 value. A term used in the industry that is not a defined term in generally accepted accounting principles. We define PV-10 as the present value of estimated future net revenues of estimated proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs. PV-10 excludes cash flows for asset retirement obligations, general and administrative expenses, derivatives, debt service and income taxes.

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

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

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

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

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

Supra-salt. A geological layer lying above the salt layer.

Undeveloped reserves. Oil and natural gas reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic 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.

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 February 27, 2013.

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 February 27, 2013.

/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/ SAMIR G. GIBARA **Samir G. Gibara**	Director
/s/ ROBERT I. ISRAEL **Robert I. Israel**	Director
/s/ STUART B. KATZ **Stuart B. Katz**	Director
/s/ S. JAMES NELSON, JR **S. James Nelson, Jr.**	Director
/s/ B. FRANK STANLEY **B. Frank Stanley**	Director

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COMPANY INFORMATION

COMPANY PROFILE

W&T Offshore, Inc. is an independent oil and natural gas company focused primarily in the Gulf of Mexico, including exploration in the deepwater and deep shelf regions, where we have developed significant technical expertise. We recently diversified our operations by expanding onshore into the Permian Basin and into East Texas. We have grown through acquisitions and exploration, with a total number of offshore fields at 72 with 69 of them now producing in federal and state waters. We currently have over 1.4 million gross acres under lease including over 710,000 gross acres on the Gulf of Mexico Shelf, over 480,000 gross acres in the deepwater and over 221,000 gross acres onshore in Texas. A substantial majority of our daily production is derived from wells we operate offshore.

CORPORATE OFFICE

W&T Offshore, Inc.
Nine Greenway Plaza, Suite 300
Houston, TX 77046
Tel 713.626.8525
Web wtoffshore.com

REGISTRAR & TRANSFER AGENT

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to the transfer agent.

Computershare Investor Services, L.L.C.
2 North La Salle Street
Chicago, IL 60602
Tel 312.588.4990
Web us.computershare.com

COMMON STOCK INFORMATION

The common stock of W&T Offshore, Inc. is traded on the New York Stock Exchange under the symbol WTI. As of February 25, 2013, there were 198 registered holders of our common stock.

INDEPENDENT AUDITORS

Ernst & Young LLP, Houston, TX

INDEPENDENT PETROLEUM CONSULTANTS

Netherland, Sewell & Associates, Inc.
1601 Elm Street, Suite 4500
Dallas, TX 75201-4754

ANNUAL MEETING

The Company's 2013 Annual Meeting of Shareholders will be held at 8 a.m. Central Time on May 7, 2013, at the Houston City Club, One City Club Drive, Houston, Texas 77046.

FORM 10-K & QUARTERLY REPORTS/INVESTOR CONTACT

A copy of the W&T Offshore, Inc. Form 10-K for fiscal 2012, filed with the Securities and Exchange Commission, is available from the Company. Requests for investor-related information should be directed to Mark Brewer, Manager, Investor Relations at the company's corporate office or on the Internet at www.wtoffshore.com. E-mail: investorrelations@wtoffshore.com. The W&T Offshore, Inc. Form 10-K is also available on our Web site at www.wtoffshore.com. The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 301 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to the Form 10-K. Tracy W. Krohn, our Chief Executive Officer, has also filed with the New York Stock Exchange the most recent Annual CEO Certification as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

W&T OFFSHORE

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