
PetroQuest Energy, Inc.
2014

About the Cover

On December 9, 2014, PetroQuest announced a significant discovery on its internally generated Thunder Bayou Prospect located in Vermilion Parish, Louisiana. The picture on the cover was taken on February 7, 2015, showing the initial production test from the well. The Company expects to commence production from Thunder Bayou in Q2'15 at a gross daily rate of more than 38 million cubic feet equivalent of natural gas. Based on internal engineering estimates, Thunder Bayou's 3P reserves are 150 billion cubic feet equivalent, representing the largest single well discovery in the Company's history.

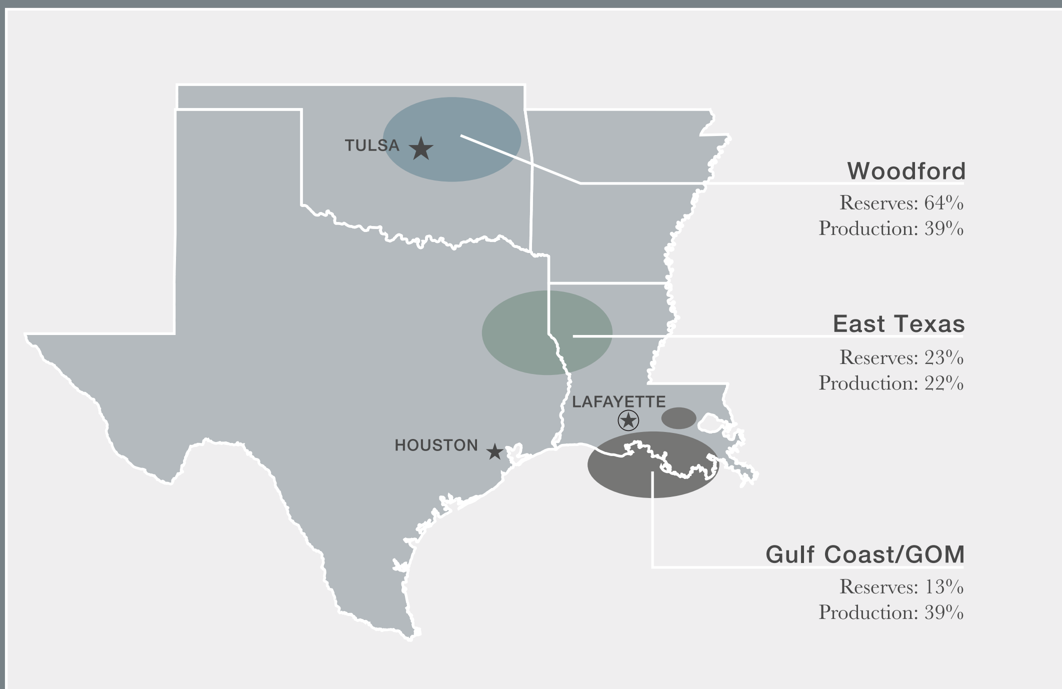
Five-Year Financial & Operational Review

	2010	2011	2012	2013	2014				2014
	Annual	Annual	Annual	Annual	Q1	Q2	Q3	Q4	Annual
Production									
Natural Gas, MMcf	24,502	24,463	27,466	29,226	7,184	7,696	8,153	7,994	31,028
NGL, MMcfe	2,470	2,288	3,367	4,754	1,131	1,658	2,397	2,296	7,482
Crude Oil, MBbl	663	572	521	681	242	230	170	160	803
Total, MMcfe	30,951	30,183	33,957	38,066	9,769	10,736	11,570	11,250	43,325
Financial ($ Thousands, except per share amounts)									
Oil and Gas Sales	$ 179,038	$ 160,486	$ 141,433	$ 182,804	$ 59,966	$ 60,581	$ 56,486	$ 47,988	$ 225,021
Net Income (Loss)	$ 47,126	$ 10,548	$ (132,079)	$ 14,082	$ 11,323	$ 10,879	$ 5,958	$ 3,030	$ 31,190
Preferred Stock Dividends	$ 5,139	$ 5,139	$ 5,139	$ 5,139	$ 1,280	$ 1,287	$ 1,287	$ 1,285	$ 5,139
Net Income (Loss) Available to Common Stockholders	$ 41,987	$ 5,409	$ (137,218)	$ 8,943	$ 10,043	$ 9,592	$ 4,671	$ 1,745	$ 26,051
Per Common Share:									
Basic	$ 0.67	$ 0.08	$ (2.20)	$ 0.14	$ 0.15	$ 0.15	$ 0.07	$ 0.03	$ 0.39
Diluted	$ 0.66	$ 0.08	$ (2.20)	$ 0.14	$ 0.15	$ 0.15	$ 0.07	$ 0.03	$ 0.39

	2010	2011	2012	2013	2014
Reserves ($ Thousands, except per unit amounts)					
Natural Gas, MMcf	174,566	241,926	188,264	250,109	309,025
NGL, MMcfe	8,373	15,111	24,366	28,430	73,498
Crude Oil, MBbl	1,623	1,395	1,635	3,031	2,437
Total, MMcfe	192,677	265,407	222,441	296,723	397,148
Percent Developed	65%	61%	76%	68%	60%
Percent Dry Gas	91%	91%	84%	84%	78%
Future Undiscounted Net Cash Flows, $000s	$ 442,505	$ 635,327	$ 402,858	$ 762,773	$ 1,093,930
SEC PV-10, Before Taxes, $000s	$ 255,651	$ 341,373	$ 237,756	$ 471,296	$ 600,711
Commodity Prices					
PetroQuest Realized, Natural Gas, $/Mcf	$ 4.37	$ 3.22	$ 2.31	$ 2.99	$ 3.69
Henry Hub Cash Market Average, Natural Gas, $/Mcf	$ 4.37	$ 4.00	$ 2.75	$ 3.73	$ 4.26
PetroQuest Realized, NGL, $/Mcfe	$ 7.78	$ 9.51	$ 6.32	$ 5.23	$ 4.31
PetroQuest Realized, Crude Oil, $/Bbl	$ 79.47	$ 104.99	$ 108.79	$ 103.49	$ 97.41
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	$ 79.51	$ 95.04	$ 94.10	$ 98.05	$ 92.91
PetroQuest Realized, Natural Gas Equivalent, $/Mcfe	$ 5.78	$ 5.32	$ 4.17	$ 4.80	$ 5.19
Per Unit Analysis, $/Mcfe					
Oil and Gas Sales	$ 5.78	$ 5.32	$ 4.17	$ 4.80	$ 5.19
Lease Operating Expense and Production Taxes	$ 1.42	$ 1.38	$ 1.17	$ 1.25	$ 1.26
Gross Operating Margin	$ 4.36	$ 3.94	$ 3.00	$ 3.55	$ 3.93
Interest Expense	$ 0.32	$ 0.32	$ 0.29	$ 0.57	$ 0.68
General and Administrative	$ 0.69	$ 0.68	$ 0.68	$ 0.70	$ 0.53
Preferred Stock Dividends	$ 0.17	$ 0.17	$ 0.15	$ 0.14	$ 0.12
Gross Cash Margin	$ 3.18	$ 2.77	$ 1.88	$ 2.14	$ 2.60

Corporate Profile

Founded in 1985, PetroQuest Energy is a U.S.-focused exploration and development company of crude oil and natural gas in Louisiana, Oklahoma and Texas. Commodity prices change but we believe our strategy is strong and flexible enough to withstand a down cycle and persevere. Our industry is a business of long-term resourcefulness balanced with near-term inventiveness. Since our founding, we've focused on building an energy company with the diversity to preserve returns through any cycle. We believe PetroQuest will persevere through the current commodity environment, add incrementally to its reserve and production base, improve well performance, and be well prepared for the future.



2014 Property Statistics

Total		Woodford	East Texas	Gulf Coast/GOM	Other
770	Gross Producing Wells	606	106	43	15
43.3	Net Production (Bcfe)	16.9	9.7	16.3	0.4
397.1	Proved Reserves (Bcfe)	252.4	89.4	55.1	0.2
308,845	Gross Leasehold Acreage	151,446	53,189	101,557	2,563

Property Profile

Thunder Bayou

For PetroQuest Energy, every successful Gulf Coast well has the potential to be a very significant cash flow generator for us. We've now drilled three La Cantera wells and recently reported a significant new discovery at Thunder Bayou. Since 2007, our Gulf Coast operations have generated more than $400 million of free cash flow. These four wells provide us great opportunity for increased production output and cash flow generation beyond 2015.

Thunder Bayou is scheduled to initiate first production in Q2'15 at a gross rate of more than 38 MMcfe per day. On a combined basis, the La Cantera and Thunder Bayou complex is expected to have gross production of approximately 100 MMcfe per day, of which 20% to 25% is crude oil and natural gas liquids. The Company's internal estimates total combined gross 3P reserves of more than 330 Bcfe for La Cantera and Thunder Bayou.

Thunder Bayou is 3.5 miles away from the Henry Hub, America's primary pricing point for natural gas.

Charles T. Goodson
Chairman, President & CEO

Letter To Shareholders

In a year that provided us with many opportunities and challenges, PetroQuest Energy achieved several important milestones. Our long-term strategies kept us balanced – not too high, not too low. Despite the rapid change in commodity prices, much value was created by the men and women of PetroQuest from our diversified asset base.

As we enter 2015, it's important to talk about one of the best operating years of our 30 years of business. Notwithstanding the extremes realized with commodity prices, PetroQuest Energy ended 2014 with the most proved reserves, producing at the highest daily rate, with a large future drilling inventory and the best professional staff – which combined provides us with a solid foundation for addressing the challenges that lie ahead.

What we experienced in the last quarter of 2014 was not caused by PetroQuest, but we did have a foreboding sense of the impact caused from a flood of crude oil. It's one thing dealing with a parish or a county to secure a drilling permit. That's easy. We're a nation of laws, governed by people who working together have created the greatest country in the history of humankind. The majority of the challenges that we dealt with in 2014 fall out of our control. We continue to witness ongoing geo-political changes in the Middle East. The civil unrest in Syria and the lingering events of the Arab Spring of 2011, which ultimately brought down dictators in three countries (Libya, Egypt and Iran), do impact what happens in America and with our operations.

Russian dictator Vladimir Putin's denial of killing innocent people over the Ukraine was a shot heard 'round the world' and new economic sanctions now have Russia on the brink of bankruptcy. Whoever said that it's improbable for a butterfly that flaps its wings in China to cause a hurricane in the U.S. Gulf Coast hasn't had to balance a spending program with cash flow from a highly volatile commodity like crude oil and natural gas, while balancing a mandate from its investors to grow and produce more today than it produced yesterday in the U.S. oil and gas industry.

The U.S. is now the largest oil and gas producer in the world. But our industry, and PetroQuest's stock price does not reflect the many successes that we all worked so hard to achieve last year. The ongoing fiscal and economic weakness in Japan, China, and the European Union is, I believe, keeping a lid on crude oil prices. As a member of the Federal Reserve Bank of Atlanta's Energy Advisory Council since November 2008, I witnessed firsthand just how far America has progressed since the start of the Great Recession.

The Great Recession is still being felt today. Japan initiated a new round of QE with a US$712 billion cash infusion last October. Will it work? It's too early to tell. Total Bank of Japan QE stimulus now stands at more than US$1.2 trillion. The U.S. ended its QE program on October 29, 2014, with total spending of $4.5 trillion. The U.S. posted a 5% GDP growth in 2014's third quarter, the highest level of growth in more than 11 years. Is this sustainable? I do not believe so, as with any expansion comes contraction. I do know this – America's future is dependent on having reliable sources of crude oil and natural gas.

What's Next?

Revenues for PetroQuest Energy in 2014 were $225.0 million. We posted net income of $26.1 million, or $0.39 per share, in 2014 compared to net income of $8.9 million, or $0.14 per share for 2013. PetroQuest's discretionary cash flow was $126.5 million in 2014, a positive change of $33.4 million, or 36%. We achieved new Company records for annual production, 43.3 Bcfe, and reserves, 397.1 Bcfe. We are forecasting a 5% to 10% increase in production in 2015 on a significantly reduced capital spending program that is planned to match our cash flow from operations.

We prefer to keep a good balance of commodity weighting of our production and reserves to handle these big swings in commodity prices. For the full year ended 2014, natural gas made up approximately 72% of our total production volumes and 78% of our reserves. On a revenue basis, 49% of our annual revenue is derived from crude oil and liquids. We have a longer-term approach when it comes to evaluating commodity prices, and manage a diversified portfolio of projects to generate acceptable rates of return in any commodity market cycle. The founding predecessor company of PetroQuest was started in 1985. In less than a year, we saw the first price crash of our generation when crude oil prices dropped to $10 barrel from $40, and the start of a natural gas bubble that lasted more than 17 years. We persevered during those dark days, and today, we believe PetroQuest is the strongest in its 30-year history. Are we going to see a commodity trough in 2015? The short answer is yes. We are managing through this commodity cycle just as we did in 2008/2009. The positive difference for PetroQuest is that we have a large inventory of projects that do not have to be drilled to just hold acreage. We have the experience to keep our spending within cash flow and adequate liquidity to drill wells that meet our investment hurdles.

Our production is estimated to grow 5% to 10% in 2015. How is it possible to cut spending and grow production? We are drilling liquids-rich Woodford wells, liquids-rich Cotton Valley wells and wells as part of our Fleetwood joint venture. Our Thunder Bayou well is scheduled to come on line in Q2'15. We have experienced excellent drilling success in each of these core operating areas, and have successfully shortened the time from spud to total depth. In reducing the spud to TD days and negotiating significant reductions in certain completion and development costs, PetroQuest can bring production to market faster and with acceptable returns for its invested capital. We will apply our strict economic tests to our drilling program so that we can generate acceptable returns. But not drilling would only shrink the Company. It's about drilling better, faster, and more economically than merely growing at an uneconomical rate.

Particular to our Company – it's all about diversification. Other companies have abandoned plays like the Gulf Coast in pursuit of shale opportunities. But the truth is we'd take a successful La Cantera or Thunder Bayou Gulf Coast well over successful shale wells any day of the week. These are world class discoveries and continue to contribute to our stable, low-risk cash flow base in Oklahoma and East Texas. Our 3P F&D cost for the four wells at La Cantera and Thunder Bayou is less than $0.50/Mcfe!

We were initially drawn to the Gulf Coast due to the sheer size of the reservoirs and the tremendous cash flow generated from these assets. During 2014, these Gulf Coast assets produced approximately $40 million of free cash flow. Thunder Bayou alone has the potential to replicate around 50% of this annual cash flow run rate. As I alluded to, we have deliberately maintained our focus and expertise in the Gulf Coast region over the years as a means to support our onshore growth projects. Again, it's all about diversifying. The excess cash generated from the Gulf Coast is an important source of funding to build, expand and develop long-life resources such as the East Texas Cotton Valley and the Oklahoma Woodford Shale.

When you invest in PetroQuest, you're investing in a company that has a balanced inventory of lower- and higher-risked exploration opportunities, which are supported by growing development opportunities with significant net asset value upside. Companies with lower-risk opportunities offer the potential for an excellent growth profile. We manage our growth through all cycles. Since 2010, we have seen a 40% increase in production, a 77% increase in our proved reserves, and our future undiscounted net cash flows jumped 147%. This is important, because during this time we were very early in the development of the Woodford acreage, were shedding production in non-core areas, and were developing better completion methodologies, like on our Cotton Valley horizontal play.

The industry is now beginning to recognize the Cotton Valley as one of the best operating areas generating attractive returns. The horizontal Cotton Valley keeps outperforming our pre-drill expectations so we continue to allocate capital to it. During 2014, our average initial production rates were 11.9 MMcfe/d representing an increase of 89% from 2011 levels. We have seen an 11x increase in EURs from horizontal wells compared to vertical wells. We have more than 700 Bcfe of gross 3P reserves on our East Texas acreage. Our Cotton Valley wells produce approximately 50 barrels of liquids per 1,000 Mcf of natural gas. Using a drill and complete cost of $5.0 million, 8.6 Bcfe EUR and $3.00 gas, the wells generate an IRR of 40% with a two-year year payout. And, the wells keep getting bigger and better. Based upon just our last eight wells, we have grown proved reserves in this area by 125% and with more than 200 identified future drilling locations, we have tremendous growth opportunities in East Texas.

In our 30-year quest for exploring and developing petroleum, we believe we have never been better positioned than we are now. I tell people that PetroQuest is a 30-year overnight success. I am enthusiastic about our future and can't wait to see it.

Sincerely,

Charles T. Goodson

Charles T. Goodson
Chairman, President and Chief Executive Officer
March 15, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2014
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: 001-32681

PETROQUEST ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	72-1440714
State of incorporation:	**I.R.S. Employer Identification No.**

400 E. Kaliste Saloom Road, Suite 6000
Lafayette, Louisiana 70508
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (337) 232-7028

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 $.001 per share	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 Web site, 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 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. (Check one):

Large accelerated filer		Accelerated filer	☒
Non-accelerated filer	(Do not check if a smaller reporting company)	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 voting common equity held by non-affiliates of the registrant as of June 30, 2014, based on the $7.52 per share closing price for the registrant's Common Stock, par value $.001 per share, as quoted on the New York Stock Exchange, was approximately $321,000,000 (for purposes of this disclosure, the registrant assumed its directors, executive officers and beneficial owners of 5% or more of the registrant's Common Stock were affiliates).

As of February 26, 2015, the registrant had outstanding 65,863,474 shares of Common Stock, par value $.001 per share.

Document incorporated by reference: portions of the definitive Proxy Statement of PetroQuest Energy, Inc. to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 with respect to the Annual Meeting of Stockholders to be held on May 20, 2015, which are incorporated by reference into Part III of this Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Form 10-K") contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-K are forward looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected.

Among those risks, trends and uncertainties are:

- the volatility of oil and natural gas prices and significantly depressed oil prices since the end of 2014;
- our indebtedness and the significant amount of cash required to service our indebtedness;
- the effects of a financial downturn or negative credit market conditions on our liquidity, business and financial condition;
- our ability to obtain adequate financing when the need arises to execute our long-term strategy and to fund our planned capital expenditures;
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by our bank credit facility and restrictive debt covenants;
- our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable;
- approximately 38% of our production being exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise;
- Securities and Exchange Commission (sometimes referred to herein as the "SEC") rules that could limit our ability to book proved undeveloped reserves in the future;
- the likelihood that our actual production, revenues and expenditures related to our reserves will differ from our estimates of proved reserves;
- our ability to identify, execute or efficiently integrate future acquisitions;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- losses or limits on potential gains resulting from hedging production;
- the loss of key management or technical personnel;
- losses and liabilities from uninsured or underinsured drilling and operating activities;
- our ability to market our oil and natural gas production;
- changes in laws and governmental regulations, increases in insurance costs or decreases in insurance availability, and delays in our offshore exploration and drilling activities that may result from the April 22, 2010 sinking of the Deepwater Horizon and subsequent oil spill in the Gulf of Mexico;
- our need to obtain bonds or other surety to maintain compliance with regulations as well as regulatory initiatives relating to oil and natural gas development, hydraulic fracturing, and derivatives;
- proposed changes to U.S. tax laws;
- competition from larger oil and natural gas companies;

- the operating hazards attendant to the oil and gas business;
- governmental regulation relating to hydraulic fracturing and environmental compliance costs and environmental liabilities;
- the operation and profitability of non-operated properties;
- potential conflicts of interest resulting from ownership of working interests and overriding royalty interests in certain of our properties by our officers and directors;
- the loss of our information and computer systems; and
- the impact of terrorist activities on global economies.

Although we believe that the expectations reflected in these forward-looking statements are reasonable, we cannot assure you that such expectations reflected in these forward looking statements will prove to have been correct.

When used in this Form 10-K, the words "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. You should be aware that the occurrence of any of the events described under "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common stock could decline, and you could lose all or part of your investment.

We cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this Form 10-K after the date of this Form 10-K.

As used in this Form 10-K, the words "we," "our," "us," "PetroQuest" and the "Company" refer to PetroQuest Energy, Inc., its predecessors and subsidiaries, except as otherwise specified. We have provided definitions for some of the oil and natural gas industry terms used in this Form 10-K in "Glossary of Certain Oil and Natural Gas Terms" beginning on page 53.

Part I

Item 1 and 2. **Business and Properties Items**

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with primary operations in Oklahoma, Texas, and the Gulf Coast Basin. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations in 1985 through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins.

We have successfully diversified into onshore, longer life basins in Oklahoma and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in East Texas through 2014, we have invested the majority of our capital into growing our longer life assets. During the eleven year period ended December 31, 2014, we have realized a 94% drilling success rate on 976 gross wells drilled. Comparing 2014 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 348% and estimated proved reserves by 377%. At

December 31, 2014, 86% of our estimated proved reserves and 62% of our 2014 production were derived from our longer life assets.

We are focused on growing our reserves and production through a balanced drilling budget with an increased emphasis on growing our oil and natural gas liquids production. In May 2010, we entered into the Woodford joint development agreement ("JDA"), which provided us with $85 million in cash during 2010 and 2011, along with a drilling carry that we have utilized since May 2010 to enhance economic returns by reducing our share of capital expenditures primarily in the Woodford Shale. Under the terms of the JDA, as amended, we will pay 25% of the cost to drill and complete wells and receive a 50% ownership interest. The drilling carry is subject to extensions in one year intervals and as of December 31, 2014, approximately $25.8 million remained available.

During 2013, we closed the Gulf of Mexico Acquisition (discussed below) which significantly enhanced our oil production. Utilizing the free cash flow provided by these acquired assets, we launched expanded drilling programs during 2014 in East Texas and the liquids rich portion of the Woodford Shale. The success of these two drilling programs, combined with a significant discovery at our Thunder Bayou prospect in the Gulf Coast Basin, were key components enabling us to achieve record annual production and record year end reserves during 2014.

Gulf of Mexico Acquisition

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million, reflecting an effective date of January 1, 2013. The Gulf of Mexico Acquisition was financed with the issuance of an additional $200 million in aggregate principal amount of our 10% Senior Notes due 2017. The acquired assets included 16 gross wells located on seven platforms.

The Gulf of Mexico Acquisition added 30.5 Bcfe of estimated proved reserves as of December 31, 2013 and increased our net acreage position in the Gulf Coast Basin by 23%. The acquired assets contributed 8.4 Bcfe and 4.5 Bcfe of total production, including 459,000 barrels and 235,000 barrels of oil, during 2014 and 2013, respectively. See "Note 2 - Acquisition" in Item 8. Financial Statements and Supplementary Data for additional details related to this transaction.

Fleetwood Joint Venture

In June 2014, we entered into a joint venture in Louisiana for an aggregate purchase price of $24 million. The assets acquired under the joint venture include an average 37% working interest in an approximately 30,000 acre leasehold position in Louisiana and exclusive rights, along with our joint venture partner, to a 200 square mile proprietary 3D survey which has generated several conventional and shallow non-conventional oil focused prospects.

The purchase price was comprised of $10 million in cash and $14 million in funding for future drilling, completion and lease acquisition costs. If the $14 million in drilling, completion and lease acquisition costs is not fully funded by December 31, 2015, any remaining balance becomes payable at the election of our joint venture partner. At December 31, 2014, $7 million of cash purchase price and $10.7 million of drilling carry remained outstanding. The $7 million of cash purchase price was paid in January 2015.

Business Strategy

Maintain Our Financial Flexibility. In response to the impact that the decline in commodity prices has had on our cash flow, our 2015 capital expenditures will be significantly reduced as compared to 2014. Our 2015 capital expenditures, which include capitalized interest and overhead but exclude acquisitions, are expected to range between $60 million and $70 million and are expected to be funded through cash flow from operations and cash on hand. To the extent our capital expenditures during 2015 exceed our cash flow from operations and cash on hand, we plan to utilize available borrowings under our bank credit facility. Because we operate approximately 88% of our total estimated proved reserves and manage the drilling and completion activities on an additional 6% of such reserves, we expect to be able to control the timing of a substantial portion of our capital investments. We also plan to maintain our commodity hedging program and, as in during prior years, we may continue to opportunistically dispose of certain assets to provide additional liquidity. During December 2012, we sold our non-operated Arkansas assets for $8.5 million. During January 2013, we sold 50% of our saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10 million. During December 2013, we sold our non-operated Wyoming assets for $1.0 million. In September 2014, we sold our Eagle Ford assets for net proceeds of approximately $9.8 million.

Pursue Balanced Growth and Portfolio Mix. We plan to pursue a risk-balanced approach to the growth and stability of our reserves, production, cash flows and earnings. Our goal is to strike a balance between lower risk development activities and higher risk and higher impact exploration activities. While our reduced 2015 capital expenditure budget, combined with lower commodity prices, is expected to impact our near-term growth outlook, we plan to allocate our capital investments in a manner that continues to geographically and operationally diversify our asset base. Through our portfolio diversification efforts, at December 31, 2014, approximately 86% of our estimated proved reserves were located in longer life and lower risk basins in Oklahoma and Texas and 14% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. In terms of production diversification, during 2014, 62% of our production was derived from longer life basins. Our 2014 production was comprised of 72% natural gas, 11% oil and 17% natural gas liquids.

Target Underexploited Properties with Substantial Opportunity for Upside. We plan to maintain a rigorous prospect selection process that enables us to leverage our operating and technical experience in our core operating areas. In evaluating these prospects, we seek properties that provide sufficient acreage for future exploration and development, as well as properties that may benefit from the latest exploration, drilling, completion and operating techniques to more economically find, produce and develop oil and gas reserves.

Concentrate in Core Operating Areas and Build Scale. We plan to continue focusing on our operations in Oklahoma, Texas and the Gulf Coast Basin. Operating in concentrated areas helps us better control our overhead by enabling us to manage a greater amount of acreage with fewer employees and minimize incremental costs of increased drilling and production. We have substantial geological and reservoir data, operating experience and partner relationships in these regions. We believe that these factors, combined with the existing infrastructure and favorable geologic conditions with multiple known oil and gas producing reservoirs in these regions, will provide us with attractive investment opportunities, as evidenced by the Gulf of Mexico Acquisition.

Manage Our Risk Exposure. We plan to continue several strategies designed to mitigate our operating risks. We have adjusted the working interest we are willing to hold based on the risk level and cost exposure of each project. For example, we typically reduce our working interests in higher risk exploration projects while retaining greater working interests in lower risk development projects. Our partners often agree to pay a disproportionate share of drilling costs relative to their interests, allowing us to allocate our capital spending to maximize our return and reduce the inherent risk in exploration and development activities. We also strive to retain operating control of the majority of our properties to control costs and timing of expenditures and we expect to continue to actively hedge a portion of our future planned production to mitigate the impact of commodity price fluctuations and achieve more predictable cash flows.

2014 Financial and Operational Summary

During 2014, we invested $197.6 million in exploratory, development and acquisition activities. We drilled 29 gross exploratory wells and 29 gross development wells realizing an overall success rate of 91%. These activities were financed through our cash flow from operations, an increase to our working capital deficit and asset sales. During 2014, our production increased 14% to 43.3Bcfe as a result of a full year of production from the wells acquired in the Gulf of Mexico Acquisition as well as the success of our Oklahoma and East Texas drilling programs. Our estimated proved reserves at December 31, 2014 increased 34% from 2013 as discussed in greater detail below.

Oil and Gas Reserves

Our estimated proved reserves at December 31, 2014 increased 34% from 2013 totaling 2.4 MMBbls of oil, 73.5 Bcfe of natural gas liquids (Ngls) and 309 Bcf of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on average prices during 2014 (“PV-10”) of $601 million. The increase in our estimated proved reserves during 2014 was primarily the result of the success of our Oklahoma and East Texas drilling programs as well as our Thunder Bayou discovery. At December 31, 2014, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $549 million. See the reconciliation of PV-10 to the standardized measure of discounted cash flows below. Our PV-10 and standardized measure of discounted cash flows utilized prices (adjusted for field differentials) for the years ended December 31, 2014 and 2013 as follows:

	12/31/2014	12/31/2013
Oil per Bbl	$96.45	$106.19
Natural gas per Mcf	$3.80	$3.11
Ngl per Mcfe	$4.11	$5.10

Ryder Scott Company, L.P., a nationally recognized independent petroleum engineering firm, prepared the estimates of our proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31, 2014. Our internal reservoir engineering staff is managed by an individual with 33 years of industry experience as a reservoir and production engineer, including twelve years as a reservoir engineering manager with PetroQuest. This individual is responsible for overseeing the estimates prepared by Ryder Scott.

Our internal controls that are used in our reserve estimation process are designed to provide reasonable assurance that our reserve estimates are computed and reported in accordance with SEC rules and regulations and GAAP. These internal controls are regularly tested in connection with our annual assessment of internal controls over financial reporting and include:

- Utilizing documented process workflows;
- Employing qualified professional engineering, geological, land, financial and marketing personnel; and
- Providing continuing education and training for all personnel involved in our reserve estimation process.

Each quarter, our Reservoir Engineering Manager presents the status of the changes to our reserve estimates to our executive team, including our Chief Executive Officer. These reserve estimates are then presented to our Board of Directors in connection with quarterly meetings. In addition, our reserve booking policies and procedures are reviewed annually by one of the members of our Board of Directors, acting on behalf of our Audit Committee.

In addition, with respect to proved undeveloped reserves ("PUD reserves"), we maintain a five year development plan that is updated and approved annually by our PUD Review Committee (as described below) with input from our executive team and asset managers and reviewed quarterly by our executive team and asset managers. Our development plan includes only PUDs that we are reasonably certain will be drilled within five years of booking based upon qualitative and quantitative factors including estimated risk-based returns, current pricing forecasts, recent drilling results, availability of services, equipment and personnel, seasonal weather patterns and changes in drilling and completion techniques and technology. Our PUD reserves are based upon our substantial basin-specific technical and operating experience relative to the location of the reserves. Over the last ten years, we have realized a 94% drilling success rate on 943 gross wells drilled in the areas where our PUD reserves are booked. Furthermore, because all of our longer life, onshore PUD reserves (92% of total PUD reserve volumes at December 31, 2014) are direct offsetting locations to producing wells, we have comprehensive data available, which enables us to forecast economic results, including drilling and operating costs, with reasonable certainty.

During 2014, we enhanced our reserve booking policies and procedures by establishing a committee that annually reviews our PUD reserves. Our PUD Review Committee (the "Committee") is comprised of our Chief Operating Officer, Executive Vice President of Operations, Chief Financial Officer and Reservoir Engineering Manager and meets annually in connection with each year-end reserve report. The Committee is responsible for reviewing all PUD locations, not only in terms of technical and financial merits as reviewed by our independent petroleum engineering firm, but also to apply a more robust evaluation of the timing and reasonable certainty of the development plan in light of all known circumstances including our budget, the outlook for commodity prices and the location of ongoing drilling programs. The Committee's evaluation of reasonable certainty of the development plan includes a thorough assessment of near term drilling plans to develop PUDs, a review of deviations to previously adopted development plans and a review of historical PUD conversion rates.

The following table sets forth certain information about our estimated proved reserves as of December 31, 2014:

	Oil (MBbls)	NGL (Mmcfe)	Natural Gas (Mmcf)	Total Mmcfe*
Proved Developed	2,089	42,584	182,567	237,688
Proved Undeveloped	348	30,914	126,458	159,460
Total Proved	2,437	73,498	309,025	397,148

* Oil conversion to Mcfe at one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

As of December 31, 2014, our PUD reserves totaled 159.5 Bcfe, a 70% increase from our PUD reserves at December 31, 2013. This increase was primarily due to extensions and discoveries as a result of our successful drilling programs in Oklahoma and East Texas, as well as our Thunder Bayou discovery. During 2014, we spent $0.3 million converting 129 MMcfe of PUD reserves at December 31, 2013 to proved developed reserves at December 31, 2014. In addition, at December 31, 2014, we had four wells in progress that are estimated to develop 15.7 Bcfe of PUD reserves in early 2015. The following table presents an analysis of the change in our PUD reserves from December 31, 2013 to December 31, 2014:

	MMcfe
PUD Reserve balance at December 31, 2013 (1)	93,571
PUD reserves converted to proved developed	(129)
PUD reserves added from revisions or extensions and discoveries	68,716
PUD reserves removed for 5 year rule	—
PUD reserves sold	(2,698)
PUD Reserve balance at December 31, 2014	159,460

(1) As of December 31, 2014, we determined that certain previously disclosed estimates of PUD reserves as of December 31, 2013 should have been reduced by 5,088 MMcfe. Accordingly, PUD reserves as of December 31, 2013 have been adjusted to reflect these revised estimates.

Approximately 65% and 27% of our PUD reserves at December 31, 2014 were associated with the future development of our Oklahoma and East Texas properties, respectively. We expect all of our PUD reserves at December 31, 2014 to be developed over the next five years including 23.7 Bcfe, or 15% of our total PUD reserves, to be developed in 2015. While we expect all of our PUD reserves to be developed over the next five years, our PUD reserve inventory does not encompass all drilling activities over the next five years. For example, during 2014 we spent $24.5 million converting 25.2 Bcfe of reserves that were direct offset locations to 2014 exploration wells. These reserves were classified as probable reserves at December 31, 2013 and proved developed producing at December 31, 2014 and therefore are not included in the above table. We expect to continue to allocate capital to projects that do not have proved reserves ascribed to them as of December 31, 2014. At December 31, 2014, we had no PUD reserves that had been booked for longer than five years. Estimated future costs related to the development of PUD reserves are expected to total $18.6 million in 2015, $68.5 million in 2016, $85.3 million in 2017, $12.7 million in 2018 and $0.7 million thereafter.

The estimated cash flows from our proved reserves at December 31, 2014 were as follows:

	Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Estimated pre-tax future net cash flows (1)	$ 742,653	$ 351,277	$ 1,093,930
Discounted pre-tax future net cash flows (PV-10) (1)	$ 460,081	$ 140,630	$ 600,711
Total standardized measure of discounted future net cash flows			$ 548,562

(1) Estimated pre-tax future net cash flows and discounted pre-tax future net cash flows (PV-10) are non-GAAP measures because they exclude income tax effects. Management believes these non-GAAP measures are useful to investors as they are based on prices, costs and discount factors which are consistent from company to company, while the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. As a result, the Company believes that investors can use these non-GAAP measures as a basis for comparison of the relative size and value of the Company’s reserves to other companies. The Company also understands that securities analysts and rating agencies use these non-GAAP measures in similar ways.

The following table reconciles undiscounted and discounted future net cash flows to standardized measure of discounted cash flows as of December 31, 2014:

	Total Proved (M$)
Estimated pre-tax future net cash flows	$ 1,093,930
10% annual discount	(493,219)
Discounted pre-tax future net cash flows	600,711
Future income taxes discounted at 10%	(52,149)
Standardized Measure of discounted future net cash flows	$ 548,562

We have not filed any reports with other federal agencies that contain an estimate of total proved net oil and gas reserves.

Core Areas

The following table sets forth estimated proved reserves and annual production from each of our core areas (in Bcfe) for the years ended December 31, 2014 and 2013.

	2014		2013	
	Reserves	Production	Reserves (3)	Production
Oklahoma Woodford	252.4	16.9	191.8	17.0
East Texas	89.4	9.7	45.3	6.0
Gulf Coast Basin (1)	55.1	16.3	57.2	14.3
Other (2)	0.2	0.4	2.4	0.8
	397.1	43.3	296.7	38.1

(1) On July 3, 2013, we closed the Gulf of Mexico Acquisition which contributed 8.4 Bcfe and 4.5 Bcfe of production in 2014 and 2013, respectively.

(2) In September 2014, we completed the sale of our Eagle Ford assets which had estimated proved reserves of 2 Bcfe at December 31, 2013.

(3) As of December 31, 2014, we determined that certain previously disclosed estimates of PUD reserves as of December 31, 2013 should have been reduced by 5.1 Bcfe. Accordingly, PUD reserves as of December 31, 2013 have been adjusted to reflect these revised estimates.

Oklahoma - Woodford

During 2014, we continued our evaluation of the Woodford Shale as we drilled and participated in 40 gross wells, achieving a 98% success rate. In total, we invested $67.4 million during 2014 acquiring prospective acreage and drilling and completing wells. In addition, during 2014 we utilized $25.8 million of total drilling carry under the amended JDA and plan to continue utilizing the drilling carry during 2015. Average daily production from our Oklahoma properties during 2014 totaled 46 MMcfe per day, a 1% decrease from 2013 average daily production. We added approximately 72 Bcfe of estimated proved reserves from our drilling program during the year. We also experienced positive revisions to our proved reserves as a result of higher average prices, which along with our drilling success resulted in a 32% increase in our estimated proved reserves. We have allocated approximately 25% of our 2015 capital budget to operations in the Woodford Shale as we expect to participate in the drilling of approximately 60 gross wells targeting our liquids rich gas and East Hoss dry gas acreage.

East Texas

During 2014, we invested $38.9 million in our East Texas properties where we drilled six gross wells, achieving a 100% success rate. Net production from our East Texas assets averaged 26.5 MMcfe per day during 2014, a 63% increase from 2013 average daily production and our estimated proved reserves increased 97% from 2013, primarily as a result of successful drilling in our Carthage field. We have allocated approximately 35% of our 2015 capital budget to drilling three gross wells as well as various re-completion and plugging and abandonment operations at our Carthage field.

Gulf Coast Basin

During 2014, we drilled four gross wells in the Gulf Coast Basin, achieving a 50% success rate. In total, we invested $73.7 million in this area including $24 million related to our Fleetwood joint venture (as described above) and $17.8 million for the Thunder Bayou discovery expected to commence production in the second quarter of 2015. Production from this area increased 14% from 2013 totaling 44.6 MMcfe per day in 2014 due to a full year of production from the wells acquired in the Gulf of Mexico Acquisition. Our estimated proved reserves in this area decreased 4% from 2013 primarily as a result of the 16.3 Bcfe of current year production, mostly offset by added proved reserves from our Thunder Bayou discovery. We have allocated approximately 40% of our 2015 capital budget to various drilling, re-completion and plugging and abandonment projects in the Gulf Coast Basin, including completion and facilities costs related to our Thunder Bayou discovery.

Markets and Customers

We sell our oil and natural gas production under fixed or floating market contracts. Customers purchase all of our oil and natural gas production at current market prices. The terms of the arrangements generally require customers to pay us within 30 days after the production month ends. As a result, if the customers were to default on their payment obligations to us, near-term earnings and cash flows would be adversely affected. However, due to the availability of other markets and pipeline connections, we do not believe that the loss of these customers or any other single customer would adversely affect our ability to market production. Our ability to market oil and natural gas from our wells depends upon numerous factors beyond our control, including:

- the extent of domestic production and imports of oil and natural gas;
- the proximity of the natural gas production to pipelines;
- the availability of capacity in such pipelines;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and natural gas production; and
- federal regulation of gas sold or transported in interstate commerce.

We cannot assure you that we will be able to market all of the oil or natural gas we produce or that favorable prices can be obtained for the oil and natural gas we produce.

In view of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we are unable to predict future oil and natural gas prices and demand or the overall effect such prices and demand will have on the Company. During 2014, one customer accounted for 30%, one accounted for 24% and one accounted for 14% of our oil and natural gas revenue. During 2013, one customer accounted for 35% and two accounted for 14% each of our oil and natural gas revenue. During 2012, one customer accounted for 30%, one accounted for 17% and one accounted for 12% of our oil and natural gas revenue. These percentages do not consider the effects of commodity hedges. We do not believe that the loss of any of our oil or natural gas purchasers would have a material adverse effect on our operations due to the availability of other purchasers.

Production, Pricing and Production Cost Data

The following table sets forth our production, pricing and production cost data during the periods indicated. Three of our core areas, Gulf Coast Basin, East Texas and Oklahoma, which includes primarily Woodford Shale reserves, represented approximately 15% or more of our total estimated proved reserves.

	Year Ended December 31,		
	2014	2013	2012
Production:			
Oil (Bbls):			
Gulf Coast Basin	687,855	512,041	346,513
East Texas	62,013	82,500	87,368
Oklahoma - Woodford	423	971	171
Other	52,218	85,468	86,538
Total Oil (Bbls)	802,509	680,980	520,590
Gas (Mcf):			
Gulf Coast Basin	10,825,424	9,876,771	5,691,109
East Texas	6,636,174	4,123,416	4,360,290
Oklahoma - Woodford	13,468,244	15,055,601	15,349,219
Other	97,829	170,055	2,065,610
Total Gas (Mcf)	31,027,671	29,225,843	27,466,228
NGL (Mcfe):			
Gulf Coast Basin	1,325,288	1,312,995	885,881
East Texas	2,672,885	1,333,725	1,479,441
Oklahoma - Woodford	3,398,750	1,971,376	947,935
Other	85,387	136,127	53,517
Total NGL (Mcfe)	7,482,310	4,754,223	3,366,774
Total Production (Mcfe):			
Gulf Coast Basin	16,277,842	14,262,012	8,656,068
East Texas	9,681,137	5,952,141	6,363,939
Oklahoma - Woodford	16,869,532	17,032,803	16,298,180
Other	496,524	818,990	2,638,355
Total Production (Mcfe)	43,325,035	38,065,946	33,956,542
Average sales prices (1):			
Oil (per Bbl):			
Gulf Coast Basin	$ 96.71	$ 105.74	$ 108.75
East Texas	92.21	98.61	104.42
Oklahoma - Woodford	97.04	90.52	92.53
Other	95.74	97.59	95.75
Total Oil (per Bbl)	96.30	103.83	105.85
Gas (per Mcf)			
Gulf Coast Basin	4.38	3.70	2.92
East Texas	4.08	3.73	2.82
Oklahoma - Woodford	3.27	2.25	1.51
Other	4.04	3.54	2.20
Total Gas (per Mcf)	3.83	2.95	2.06
NGL (per Mcfe)			
Gulf Coast Basin	6.00	7.12	8.45
East Texas	4.17	4.70	5.72
Oklahoma - Woodford	3.63	4.31	4.49
Other	5.55	5.21	6.30
Total NGL (per Mcfe)	4.27	5.22	6.10
Total Per Mcfe:			
Gulf Coast Basin	7.49	7.02	7.14
East Texas	4.54	5.00	4.69
Oklahoma - Woodford	3.34	2.49	1.69
Other	11.82	11.79	4.99
Total Per Mcfe	5.26	4.78	3.90

	Year Ended December 31,		
	2014	2013	2012
Average Production Cost per Mcfe (2):			
Gulf Coast Basin	$ 1.59	$ 1.60	$ 1.78
East Texas	1.21	1.47	1.56
Oklahoma - Woodford	0.52	0.47	0.49
Other	4.56	5.03	2.12
Total Average Production Cost per Mcfe	1.12	1.15	1.15

(1) Does not include the effect of hedges.
(2) Production costs do not include production taxes.

Oil and Gas Producing Wells

The following table details the productive wells in which we owned an interest as of December 31, 2014:

	Gross	Net
Productive Wells:		
Oil:		
Gulf Coast Basin	20	10.79
East Texas	3	2.53
Oklahoma - Woodford	1	0.03
Other	14	4.15
	38	17.50
Gas:		
Gulf Coast Basin	23	11.71
East Texas	103	67.94
Oklahoma - Woodford	605	171.54
Other	1	0.45
	732	251.64
Total	770	269.14

Of the 770 gross productive wells at December 31, 2014, two had dual completions.

Oil and Gas Drilling Activity

The following table sets forth the wells drilled and completed by us during the periods indicated. All wells were drilled in the continental United States.

	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive:						
Gulf Coast Basin	2	1.19	1	0.94	2	0.74
East Texas	4	3.10	1	0.99	6	3.25
Oklahoma - Woodford	15	6.58	22	5.66	30	7.15
Other	4	0.56	7	2.11	46	4.73
	25	11.43	31	9.70	84	15.87
Non-productive:						
Gulf Coast Basin	2	1.12	3	0.62	—	—
East Texas	—	—	—	—	—	—
Oklahoma - Woodford	—	—	—	—	1	0.34
Other	2	2	2	0.62	1	0.50
	4	3.12	5	1.24	2	0.84
Total	29	14.55	36	10.94	86	16.71
Development:						
Productive:						
Gulf Coast Basin	—	—	1	0.24	—	—
East Texas	2	1.55	—	—	—	—
Oklahoma - Woodford	24	5.86	3	1.36	15	4.78
Other	2	0.19	—	—	6	0.10
	28	7.60	4	1.60	21	4.88
Non-productive:						
Gulf Coast Basin	—	—	—	—	—	—
East Texas	—	—	—	—	—	—
Oklahoma - Woodford	1	0.50	—	—	—	—
Other	—	—	—	—	—	—
	1	0.50	—	—	—	—
Total	29	8.10	4	1.60	21	4.88

At December 31, 2014, we had 17 gross (7.13 net) wells in progress.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2014:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Kansas	—	—	2,563	1,282
Louisiana	3,126	929	40,019	18,236
Mississippi	721	721	—	—
Oklahoma	94,954	35,778	56,492	26,649
Texas	44,425	23,781	8,764	4,276
Federal Waters	50,657	31,471	7,124	7,124
Total	193,883	92,680	114,962	57,567

Leases covering 20% of our net undeveloped acreage are scheduled to expire in 2015, 30% in 2016, 7% in 2017 and 43% thereafter. At December 31, 2014, we do not have any PUD reserves attributed to acreage that has an expiration date preceding the scheduled date for initial development. Of the acreage subject to leases scheduled to expire during 2015, 73% relates to undeveloped acreage in the Mississippian Lime trend where we are currently evaluating future plans.

Title to Properties

Title to properties is subject to contractual arrangements customary in the oil and gas industry, liens for taxes not yet due and, in some instances, other encumbrances. We believe that such burdens do not materially detract from the value of properties or from the respective interests therein or materially interfere with their use in the operation of the business.

As is customary in the industry, other than a preliminary review of local records, little investigation of record title is made at the time of acquisitions of undeveloped properties. Investigations, which generally include a title opinion of outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Our properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind that we own.

Federal Regulations

Sales and Transportation of Natural Gas. Historically, the transportation and sales for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (“NGA”), the Natural Gas Policy Act of 1978 and the Federal Energy Regulatory Commission (“FERC”) regulations. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated the price for all “first sales” of natural gas. Thus, all of our sales of gas may be made at market prices, subject to applicable contract provisions. Sales of natural gas are affected by the availability, terms and cost of pipeline transportation. Since 1985, the FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis. We cannot predict what further action the FERC will take on these matters. Some of the FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

The Outer Continental Shelf Lands Act (the “OCSLA”), which was administered by the Bureau of Ocean Energy Management, Regulation and Enforcement (the “BOEMRE”) and, after October 1, 2011, its successors, the Bureau of Ocean Energy Management (the “BOEM”) the Bureau of Safety and Environmental Enforcement (the “BSEE”), and the FERC, requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its NGA jurisdiction. Therefore, we do not believe that any FERC, BOEM or BSEE action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

Our natural gas sales are generally made at the prevailing market price at the time of sale. Therefore, even though we sell significant volumes to major purchasers, we believe that other purchasers would be willing to buy our natural gas at comparable market prices.

Natural gas continues to supply a significant portion of North America's energy needs and we believe the importance of natural gas in meeting this energy need will continue. The impact of the sudden drop in crude oil prices has not yet had a significant impact on gas prices, but a continued drop in crude oil prices could eventually impact gas markets. At this time, we are not in a position to predict the scope of any loss of market due to lower crude oil prices.

On August 8, 2005, the Energy Policy Act of 2005 (the “2005 EPA”) was signed into law. This comprehensive act contains many provisions that will encourage oil and gas exploration and development in the U.S. The 2005 EPA directs the FERC, BOEM and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. The 2005 EPA amends the NGA to make it unlawful for “any entity”, including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. To date, we do not believe we have been, nor do we anticipate we will be affected any differently than other producers of natural gas.

In 2007, the FERC issued a final rule on annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (“Order 704”). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. The monitoring and reporting required by these rules have increased our administrative costs. To date, we do not believe we have been, nor do we anticipate that we will be affected any differently than other producers of natural gas.

Sales and Transportation of Crude Oil. The spot markets for oil, gas and NGLs are subject to volatility and supply and demand factors fluctuations. Our sales of crude oil, condensate and natural gas liquids are not currently regulated, and are subject to applicable contract provisions made at market prices and typically under short term agreements with third parties. Additionally, we may periodically enter into financial hedging arrangements or fixed-price contracts associated with a portion of our oil, gas or natural gas liquids production. 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 the FERC's jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally more light-handed than the FERC's regulation of gas pipelines under the NGA. Regulated pipelines that transport crude oil, condensate, and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Federal Leases. We maintain operations located on federal oil and natural gas leases, which are administered by the BOEM or the BSEE, pursuant to the OCSLA. The BOEM and the BSEE regulate offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Gulf of Mexico shelf, and removal of facilities.

The BOEM handles offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, NEPA analysis and environmental studies, and the BSEE is responsible for the safety and enforcement functions of offshore oil and gas operations, including the development and enforcement of safety and environmental regulations, permitting of offshore exploration, development and production activities, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs. Our federal oil and natural gas leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed regulations and orders that are subject to interpretation and change by the BOEM or BSEE. We are currently subject to regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures and pipelines, and the BOEM or the BSEE may in the future amend these regulations. Please read "Risk Factors" beginning on page 19 for more information on new regulations.

To cover the various obligations of lessees on the Outer Continental Shelf (the "OCS"), the BOEM and the BSEE generally require that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. While we have been exempt from such supplemental bonding requirements in the past, beginning in 2014 we were required to post supplemental bonding or alternate form of collateral for certain of our offshore properties. We have been able to satisfy the collateral requirements using a combination of our existing cash on hand and the issuance of supplemental bonds. The cost of compliance with these supplemental bonding requirements has not been material. 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. As a result of certain bankruptcies of Gulf of Mexico operations, BSEE and BOEM are currently reassessing decommissioning liability and supplemental bonding requirements for all operations on the GOM OCS with respect to decommissioning wells and platforms in the Gulf of Mexico and are updating all decommissioning costs in the Gulf of Mexico. The Department of the Interior through the BOEM and BSEE have made enforcement of decommissioning liabilities one of its top priorities. Recent DOI guidance has indicated that well abandonment and decommissioning requirements are not necessarily tied to lease termination. Based on the ongoing review of such decommissioning and abandonment costs, the Company's potential liability for such costs has become more expensive and as a result supplemental bonding costs may continue to increase.

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 pipelines, wells, fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEM and the BSEE will 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 BOEMRE historically 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 or the BSEE for future hurricane seasons. New requirements, if any, could increase our operating costs to future storms.

The Office of Natural Resources Revenue (the "ONRR") in the U.S. Department of the Interior 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.

Federal, State or American Indian Leases. In the event we conduct operations on federal, state or American Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management ("BLM") or the BOEM or other appropriate federal or state agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be cancelled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that holders of our equity interests may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

State Regulations

Most states regulate the production and sale of oil and natural gas, including:

- requirements for obtaining drilling permits;
- the method of developing new fields;
- the spacing and operation of wells;

- the prevention of waste of oil and gas resources; and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

We may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates that we could charge for gas, the transportation of gas, and the construction and operation of such pipeline would be subject to the rules and regulations governing such matters, if any, of such administrative authority.

Legislative Proposals

In the past, Congress has been very active in the area of natural gas regulation. New legislative proposals in Congress and the various state legislatures, if enacted, could significantly affect the petroleum industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on our operations.

Environmental Regulations

General. Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, regulations and rules regulating the release of materials into the environment or otherwise relating to the protection of human health, safety and the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect additional regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Our activities with respect to exploration and production of oil and natural gas, including the drilling of wells and the operation and construction of pipelines and other facilities for extracting, transporting or storing natural gas and other petroleum products, are subject to stringent environmental regulation by state and federal authorities, including the United States Environmental Protection Agency (the "USEPA"). Such regulation can increase the cost of planning, designing, installing and operating such facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities are inherent in oil and gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover it is possible that other developments, such as spills or other unanticipated releases, stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production, would result in substantial costs and liabilities to us.

Solid and Hazardous Waste. We own or lease numerous properties that have been used for production of oil and gas for many years. Although we have utilized operating and disposal practices standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under these properties. In addition, many of these properties have been operated by third parties that controlled the treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

We generate wastes, including hazardous wastes, which are subject to regulation under the federal Resource Conservation and Recovery Act ("RCRA") and state statutes. The USEPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes generated by our oil and gas operations which are currently exempt from regulation as "hazardous wastes" may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly disposal requirements.

Naturally Occurring Radioactive Materials ("NORM") are radioactive materials which precipitate on production equipment or area soils during oil and natural gas extraction or processing. NORM wastes are regulated under the RCRA framework, although such wastes may qualify for the oil and gas hazardous waste exclusion. Primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM-contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release or threatened release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed or arranged for the disposal of hazardous substances at a site. CERCLA also authorizes the USEPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs of such action. State statutes impose similar liability.

Under CERCLA, the term "hazardous substance" does not include "petroleum, including crude oil or any fraction thereof," unless specifically listed or designated and the term does not include natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel. While this "petroleum exclusion" lessens the significance of CERCLA to our operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance" in the course of our ordinary operations. We also currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and, to our knowledge, our predecessors have used operating and disposal practices that were standard in the industry at the time, "hazardous substances" may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. At this time, we do not believe that we have any liability associated with any Superfund site, and we have not been notified of any claim, liability or damages under CERCLA.

Endangered Species Act. Federal and state legislation including, in particular, the federal Endangered Species Act of 1973 ("ESA"), impose requirements to protect imperiled species from extinction by conserving and protecting threatened and endangered species and the habitat upon which they depend. With specified exceptions, the ESA prohibits the "taking," including killing, harassing or harming, of any listed threatened or endangered species, as well as any degradation or destruction of its habitat. In addition, the ESA mandates that federal agencies carry out programs for conservation of listed species. Many state laws similarly protect threatened and endangered species and their habitat. We operate in areas in which listed species may be present. For example, the American Burying Beetle, listed in 1989 as endangered, is present in regions overlying the Woodford Shale in Oklahoma. As a result, we may be required to adopt protective measures, obtain incidental take permits, and otherwise adjust our drilling plans to comply with ESA requirements.

Oil Pollution Act. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulations. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA establishes a liability limit for onshore facilities of $350 million and for offshore facilities of all removal costs plus $33.65 million, and lesser limits for some vessels depending upon their size. The Coast Guard has proposed to increase the onshore liability limit to $404.6 million based on an inflation adjustment. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges and other factors. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

As a result of the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in 2010, Congress considered but did not enact legislation that would eliminate the current cap on liability for damages and increase minimum levels of financial responsibility under OPA. If enacted, such legislation could increase our obligations and potential liability, but adoption of such legislation is uncertain. We are not aware of the occurrence of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Discharges. The Clean Water Act ("CWA") regulates the discharge of pollutants to waters of the United States, including wetlands, and requires a permit for the discharge of pollutants, including petroleum, to such waters. The CWA also requires a permit for the discharge of dredged or fill material into wetlands. A revised definition of "Waters of the United States" has been proposed and, if adopted, would likely expand requirements for CWA permitting. Certain facilities that store or otherwise handle oil are required to prepare and implement Spill Prevention, Control and Countermeasure Plans and Facility Response Plans relating to the possible discharge of oil to surface waters. We are required to prepare and comply with such plans and to obtain and comply with discharge permits. We believe we are in substantial compliance with these requirements and that any noncompliance would not have a material adverse effect on us. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide civil and criminal penalties and liabilities for spills to both surface and groundwaters and require permits that set limits on discharges to such waters.

Hydraulic Fracturing. Our exploration and production activities may involve the use of hydraulic fracturing techniques to stimulate wells and maximize natural gas production. Citing concerns over the potential for hydraulic fracturing to impact drinking water, human health and the environment, and in response to a Congressional directive, the USEPA has commissioned a study to identify potential risks associated with hydraulic fracturing. The USEPA published a progress report on this study in December 2012, but has delayed release of its final draft report previously expected in 2014. Additionally, in May 2012 the BLM proposed to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposal, issued a revised proposal in May 2013. The revised proposal, which also addresses disclosure of fluids used in the hydraulic fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process, has also generated substantial public comment and no final rule has yet been promulgated. Some states now regulate utilization of hydraulic fracturing and others are in the process of developing, or are considering development of, such rules to address the potential for drinking water impacts, induced seismicity, and other concerns. In several localities and in New York, use of hydraulic fracturing has been banned. Depending on the results of the USEPA study and other developments related to the impact of hydraulic fracturing, our drilling activities could be subjected to new or enhanced federal, state and/or local requirements governing hydraulic fracturing.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Administrative enforcement actions for failure to comply strictly with air regulations or permits may be resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could impose civil and criminal liability for non-compliance. An agency could require us to forego construction or operation of certain air emission sources. We believe that we are in substantial compliance with air pollution control requirements.

According to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases (“GHG”) may be contributing to global warming of the earth's atmosphere and to global climate change. In response to the scientific studies, legislative and regulatory initiatives have been underway to limit GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act (“CAA”) definition of an “air pollutant”, and in response the USEPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. The USEPA has also promulgated rules requiring large sources to report their GHG emissions. Sources subject to these reporting requirements include on- and offshore petroleum and natural gas production and onshore natural gas processing and distribution facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year in aggregate emissions from all site sources. We are not subject to GHG reporting requirements. In addition, the USEPA promulgated rules that significantly increase the GHG emission threshold that would identify major stationary sources of GHG subject to CAA permitting programs. As currently written and based on current Company operations, we are not subject to federal GHG permitting requirements. Regulation of GHG emissions is developing and highly controversial, and further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact the Company. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, the Company cannot predict the financial impact of related developments on the Company.

The USEPA has promulgated rules to limit air emissions from many hydraulically fractured natural gas wells. These regulations require use of equipment to capture gases that come from the well during the drilling process (so-called green completions). Other new requirements mandate tighter standards for emissions associated with gas production, storage and transport. While these new requirements are expected to increase the cost of natural gas production, we do not anticipate that we will be affected any differently than other producers of natural gas.

Coastal Coordination. There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act (“CZMA”) was passed to preserve and, where possible, restore the natural resources of the Nation's coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development.

The Louisiana Coastal Zone Management Program (“LCZMP”) was established to protect, develop and, where feasible, restore and enhance coastal resources of the state. Under the LCZMP, coastal use permits are required for certain activities, even if the activity only partially infringes on the coastal zone. Among other things, projects involving use of state lands and water bottoms, dredge or fill activities that intersect with more than one body of water, mineral activities, including the exploration and production of oil and gas, and pipelines for the gathering, transportation or transmission of oil, gas and other minerals require such permits. General permits, which entail a reduced administrative burden, are available for a number of routine oil and gas activities. The LCZMP and its requirement to obtain coastal use permits may result in additional permitting requirements and associated project schedule constraints.

The Texas Coastal Coordination Act ("CCA") provides for coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development and establishes the Texas Coastal Management Program that applies in the nineteen counties that border the Gulf of Mexico and its tidal bays. The CCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. This review may affect agency permitting and may add a further regulatory layer to some of our projects.

OSHA. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the USEPA community right-to-know regulations under Title III of the federal Superfund Amendments and Reauthorization Act, and similar state statutes require us to organize and/or disclose information about hazardous materials used or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

Management believes that we are in substantial compliance with current applicable environmental laws and regulations described above and that continued compliance with existing requirements will not have a material adverse impact on us.

Corporate Offices

Our headquarters are located in Lafayette, Louisiana, in approximately 49,200 square feet of leased space, with exploration offices in The Woodlands, Texas and Tulsa, Oklahoma, in approximately 13,100 square feet and 11,800 square feet, respectively, of leased space. We also maintain owned or leased field offices in the areas of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available.

Employees

We had 141 full-time employees as of February 10, 2015. In addition to our full time employees, we utilize the services of independent contractors to perform certain functions. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement.

Available Information

We make available free of charge, or through the "Investors—SEC Documents" section of our website at www.petroquest.com, access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is filed or furnished to the Securities and Exchange Commission. Our Code of Business Conduct and Ethics, our Corporate Governance Guidelines and the charters of our Audit, Compensation and Nominating and Corporate Governance Committees are also available through the "Investors—Corporate Governance" section of our website or in print to any stockholder who requests them.

Item 1A. **Risk Factors**

Risks Related to Our Business, Industry and Strategy

Oil and natural gas prices are volatile and oil prices have been significantly depressed since the end of 2014. An extended decline in the prices of oil and natural gas would likely have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our future financial condition, revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend primarily on the prices we receive for our oil and natural gas production. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon oil and natural gas prices. Historically, the markets for oil and natural gas have been volatile and oil prices have been significantly depressed since the end of 2014. For example, for the five years ended December 31, 2014, the NYMEX-WTI oil price ranged from a high of $113.93 per Bbl to a low of $53.27 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $6.15 per MMBtu to a low of $1.91 per MMBtu. These markets will likely continue to be volatile in the future. The prices we will receive for our production, and the levels of our production, will depend on numerous factors beyond our control.

These factors include:

- relatively minor changes in the supply of or the demand for oil and natural gas;
- the condition of the United States and worldwide economies;

- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States, such as hurricanes;
- the actions of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulation and taxes, including price controls adopted by the FERC;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East and South America;
- the price and level of foreign imports of oil and natural gas; and
- the price and availability of alternate fuel sources.

We cannot predict future oil and natural gas prices and such prices may decline. An extended decline in oil and natural gas prices may adversely affect our financial condition, liquidity, ability to meet our financial obligations and results of operations. Lower prices have reduced and may further reduce the amount of oil and natural gas that we can produce economically and has required and may require us to record additional ceiling test write-downs and may cause our estimated proved reserves at December 31, 2015 to decline compared to our estimated proved reserves at December 31, 2014. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices. Our sales are not made pursuant to long-term fixed price contracts.

To attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our outstanding indebtedness may adversely affect our cash flow and our ability to operate our business, which in turn may limit our ability to remain in compliance with debt covenants and make payments on our debt.

The aggregate principal amount of our outstanding indebtedness, net of cash on hand, as of December 31, 2014 was $407 million. We have $95 million of additional availability under our bank credit facility, subject, however, to limitations on incurrence of indebtedness under the indenture governing our 10% Senior Notes due 2017 (the "10% senior notes"). In addition, we may also incur additional indebtedness in the future. Specifically, our high level of debt could have important consequences for you, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our outstanding indebtedness, including our 10% senior notes, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing such indebtedness;
- the covenants contained in our debt agreements limit our ability to borrow money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations and may limit our flexibility in operating our business;
- we will need to use a substantial portion of our cash flows to pay interest on our debt, approximately $35 million per year for interest on our 10% senior notes alone, and to pay quarterly dividends, if declared by our Board of Directors, on our 6.875% Series B Cumulative Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") of approximately $5.1 million per year, which will reduce the amount of money we have for operations, capital expenditures, expansion, acquisitions or general corporate or other business activities;
- the amount of our interest expense may increase because certain of our borrowings in the future may be at variable rates of interest, which, if interest rates increase, could result in higher interest expense;
- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;

- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially extended or further declines in oil and natural gas prices; and

- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow from operations will be sufficient to allow us to pay the principal and interest on our debt, including our 10% senior notes, and meet our other obligations. If we do not have enough cash to service our debt, we may be required to refinance all or part of our existing debt, including our 10% senior notes, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make payments on and to refinance our indebtedness, including our 10% senior notes, and to fund planned capital expenditures will depend on our ability to generate sufficient cash flow from operations in the future. To a certain extent, this is subject to general economic, financial, competitive, legislative and regulatory conditions and other factors that are beyond our control, including the prices that we receive for our oil and natural gas production.

We cannot assure you that our business will generate sufficient cash flow from operations or that future borrowings will be available to us under our bank credit facility in an amount sufficient to enable us to pay principal and interest on our indebtedness, including our 10% senior notes, or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to reduce our planned capital expenditures, sell assets, seek additional equity or debt capital or restructure our debt. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, including payments on our 10% senior notes, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and could impair our liquidity.

A financial downturn or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot predict.

Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to obtain capital in the long-term or short-term debt capital markets or equity capital markets or an inability to access bank financing. A prolonged credit crisis or turmoil in the domestic or global financial systems could materially affect our liquidity, business and financial condition. These conditions have adversely impacted financial markets previously and created substantial volatility and uncertainty, and could do so again, with the related negative impact on global economic activity and the financial markets. Negative credit market conditions could materially affect our liquidity and may inhibit our lenders from fully funding our bank credit facility or cause them to make the terms of our bank credit facility costlier and more restrictive. A weak economic environment could also adversely affect the collectability of our trade receivables or performance by our suppliers and cause our commodity derivative arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, negative economic conditions could lead to reduced demand for oil, natural gas and NGLs or lower prices for oil, natural gas and NGLs, which could have a negative impact on our revenues.

We may not be able to obtain adequate financing when the need arises to execute our long-term operating strategy.

Our ability to execute our long-term operating strategy is highly dependent on having access to capital when the need arises. We historically have addressed our long-term liquidity needs through bank credit facilities, second lien term credit facilities, issuances of equity and debt securities, sales of assets, joint ventures and cash provided by operating activities. We will examine the following alternative sources of long-term capital as dictated by current economic conditions:

- borrowings from banks or other lenders;

- the sale of certain assets;

- the issuance of debt securities;

- the sale of common stock, preferred stock or other equity securities;
- joint venture financing; and
- production payments.

The availability of these sources of capital when the need arises will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices, our credit ratings, interest rates, market perceptions of us or the oil and gas industry, our market value and our operating performance. We may be unable to execute our long-term operating strategy if we cannot obtain capital from these sources when the need arises.

The borrowing base under our bank credit facility may be reduced below the amount of borrowings outstanding under such facility.

Under the terms of our bank credit facility, our borrowing base is subject to redeterminations at least semi-annually based in part on prevailing oil and gas prices. A negative adjustment could occur if the estimates of future prices used by the banks in calculating the borrowing base are significantly lower than those used in the last redetermination. The next redetermination of our borrowing base is scheduled to occur by March 31, 2015. In addition, the portion of our borrowing base made available to us is subject to the terms and covenants of the bank credit facility including, without limitation, compliance with the ratios and other financial covenants of such facility. In the event the amount outstanding under our bank credit facility exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell a portion of our assets.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our bank credit facility and the indenture governing our 10% senior notes contain a number of significant covenants that, among other things, restrict or limit our ability to:

- pay dividends or distributions on our capital stock or issue preferred stock;
- repurchase, redeem or retire our capital stock or subordinated debt;
- make certain loans and investments;
- place restrictions on the ability of subsidiaries to make distributions;
- sell assets, including the capital stock of subsidiaries;
- enter into certain transactions with affiliates;
- create or assume certain liens on our assets;
- enter into sale and leaseback transactions;
- merge or to enter into other business combination transactions;
- enter into transactions that would result in a change of control of us; or
- engage in other corporate activities.

Also, our bank credit facility and the indenture governing our 10% senior notes require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our bank credit facility and the indenture governing our 10% senior notes impose on us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our bank credit facility and our 10% senior notes. A default, if not cured or waived, could result in all indebtedness outstanding under our bank credit facility and our 10% senior notes to become immediately due and payable. If that should occur, we may not be able to pay all such debt or borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. If we were unable to repay those amounts, the lenders could accelerate the maturity of the debt or proceed against any collateral granted to them to secure such defaulted debt.

Our future success depends upon our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable.

As is generally the case in the Gulf Coast Basin where approximately 38% of our current production is located, many of our producing properties are characterized by a high initial production rate, followed by a steep decline in production. In order to maintain or increase our reserves, we must constantly locate and develop or acquire new oil and natural gas reserves to replace those being depleted by production. We must do this even during periods of low oil and natural gas prices when it is difficult to raise the capital necessary to finance our exploration, development and acquisition activities. Without successful exploration, development or acquisition activities, our reserves and revenues will decline rapidly. We may not be able to find and develop or acquire additional reserves at an acceptable cost or have access to necessary financing for these activities, either of which would have a material adverse effect on our financial condition.

Approximately 38% of our production is exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise.

At December 31, 2014, approximately 38% of our production and approximately 14% of our estimated proved reserves are located in the Gulf of Mexico and along the Gulf Coast Basin. Operations in this area are subject to severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise. Some of these adverse conditions can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, certain of our Gulf Coast Basin properties have experienced damages and production downtime as a result of storms including Hurricanes Katrina and Rita, and more recently Hurricanes Gustav and Ike. In addition, according to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases may be contributing to global warming of the earth's atmosphere and to global climate change, which may exacerbate the severity of these adverse conditions. As a result, such conditions may pose increased climate-related risks to our assets and operations.

In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks; however, losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

SEC rules could limit our ability to book additional proved undeveloped reserves or require us to write down our proved undeveloped reserves.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year time frame.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.

Although the estimates of our oil and natural gas reserves and future net cash flows attributable to those reserves were prepared by Ryder Scott Company, L.P., our independent petroleum and geological engineers, we are ultimately responsible for the disclosure of those estimates. Reserve engineering is a complex and subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and natural gas prices; and

- assumptions concerning future operating costs, severance and excise taxes, development costs and work-over and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and natural gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Historically, the difference between our actual production and the production estimated in a prior year's reserve report has not been material. Our 2014 production, excluding the impact from successful exploration wells which are not included in the prior year reserve report, was approximately 14% lower than amounts projected in our 2013 reserve report. We cannot assure you that these differences will not be material in the future.

Approximately 40% of our estimated proved reserves at December 31, 2014 are undeveloped and 6% were developed, non-producing. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop and produce our reserves. Although we have prepared estimates of our oil and natural gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated. In addition, the recovery of certain developed non-producing reserves (primarily in the Gulf of Mexico) is generally subject to the approval of development plans and related activities by applicable state and/or federal agencies. Statutes and regulations may affect both the timing and quantity of recovery of estimated reserves. Such statutes and regulations, and their enforcement, have changed in the past and may change in the future, and may result in upward or downward revisions to current estimated proved reserves.

You should not assume that the standardized measure of discounted cash flows is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the standardized measure of discounted cash flows from proved reserves at December 31, 2014 are based on twelve-month average prices and costs as of the date of the estimate. These prices and costs will change and may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by oil and natural gas purchasers or in governmental regulations or taxation may also affect actual future net cash flows. The actual timing of development activities, including related production and expenses, will affect the timing of future net cash flows and any differences between estimated development timing and actual could have a material effect on standardized measure. In addition, the 10% discount factor we use when calculating standardized measure of discounted cash flows for reporting requirements in compliance with accounting requirements is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our operations or the oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

We may be unable to successfully identify, execute or effectively integrate future acquisitions, which may negatively affect our results of operations.

Acquisitions of oil and gas businesses and properties have been an important element of our business, and we will continue to pursue acquisitions in the future. In the last several years, we have pursued and consummated acquisitions that have provided us opportunities to grow our production and reserves. Although we regularly engage in discussions with, and submit proposals to, acquisition candidates, suitable acquisitions may not be available in the future on reasonable terms. If we do identify an appropriate acquisition candidate, we may be unable to successfully negotiate the terms of an acquisition, finance the acquisition or, if the acquisition occurs, effectively integrate the acquired business into our existing business. Negotiations of potential acquisitions and the integration of acquired business operations may require a disproportionate amount of management's attention and our resources. Even if we complete additional acquisitions, continued acquisition financing may not be available or available on reasonable terms, any new businesses may not generate revenues comparable to our existing business, the anticipated cost efficiencies or synergies may not be realized and these businesses may not be integrated successfully or operated profitably. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. Our inability to successfully identify, execute or effectively integrate future acquisitions may negatively affect our results of operations.

Even though we perform due diligence reviews (including a review of title and other records) of the major properties we seek to acquire that we believe is consistent with industry practices, these reviews are inherently incomplete. It is generally not feasible for us to perform an in-depth review of every individual property and all records involved in each acquisition. However, even an in-depth review of records and properties may not necessarily reveal existing or potential problems or permit us to become familiar enough with the properties to assess fully their deficiencies and potential. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with the acquired businesses and properties. The discovery of any material liabilities associated with our acquisitions could harm our results of operations.

In addition, acquisitions of businesses may require additional debt or equity financing, resulting in additional leverage or dilution of ownership. Our bank credit facility contains certain covenants that limit, or which may have the effect of limiting, among other things acquisitions, capital expenditures, the sale of assets and the incurrence of additional indebtedness.

Hedging production may limit potential gains from increases in commodity prices or result in losses.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. Our hedges at December 31, 2014 are in the form of swaps placed with the commodity trading branches of JPMorgan Chase Bank, Wells Fargo Bank, Bank of America, The Bank of Nova Scotia and Capital One, N.A., all of which participate in our bank credit facility. We cannot assure you that these or future counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the counterparty to the hedging contract defaults on the contractual obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements may limit the benefit we could receive from increases in the market or spot prices for oil and natural gas. Oil and natural gas hedges increased (decreased) our total oil and gas sales by approximately ($3.0) million, $0.9 million and $9.1 million during 2014, 2013 and 2012, respectively. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil and natural gas prices.

The loss of key management or technical personnel could adversely affect our ability to operate.

Our operations are dependent upon a diverse group of key senior management and technical personnel. In addition, we employ numerous other skilled technical personnel, including geologists, geophysicists and engineers that are essential to our operations. We cannot assure you that such individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of any of these key management or technical personnel could have an adverse effect on our operations.

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

We maintain several types of insurance to cover our operations, including worker's compensation, maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies. We also maintain operator's extra expense coverage, which covers the control of drilling or producing wells as well as redrilling expenses and pollution coverage for wells out of control.

We may not be able to maintain adequate insurance in the future at rates we consider reasonable, or we could experience losses that are not insured or that exceed the maximum limits under our insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect our financial condition and results of operations.

Lower oil and natural gas prices may cause us to record ceiling test write-downs, which could negatively impact our results of operations.

We use the full cost method of accounting to account for our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of oil and natural gas properties may not exceed a "full cost ceiling" which is based upon the present value of estimated future net cash flows from proved reserves, including the effect of hedges in place, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If at the end of any fiscal period we determine that the net capitalized costs of oil and natural gas properties exceed the full cost ceiling, we must charge the amount of the excess to earnings in the period then ended. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our net income and stockholders' equity. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

We review the net capitalized costs of our properties quarterly, using a single price based on the beginning of the month average of oil and natural gas prices for the prior 12 months. We also assess investments in unproved properties periodically to determine whether impairment has occurred. The risk that we will be required to further write down the carrying value of our oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. As a result of the decline in commodity prices, we recognized a ceiling test write-down totaling $137.1 million during the year ended December 31, 2012. While no such write-downs occurred during 2014 or 2013, we may experience further ceiling test write-downs or other impairments in the future. In addition, any future ceiling test cushion would be subject to fluctuation as a result of acquisition or divestiture activity.

Factors beyond our control affect our ability to market oil and natural gas.

The availability of markets and the volatility of product prices are beyond our control and represent a significant risk. The marketability of our production depends upon the availability and capacity of natural gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Our ability to market oil and natural gas also depends on other factors beyond our control. These factors include:

- the level of domestic production and imports of oil and natural gas;
- the proximity of natural gas production to natural gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternate fuel sources;
- the effect of inclement weather, such as hurricanes;
- state and federal regulation of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

If these factors were to change dramatically, our ability to market oil and natural gas or obtain favorable prices for our oil and natural gas could be adversely affected.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly increase our risks, costs and delays.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly impact the risks we face. The Deepwater Horizon incident and resulting legislative, regulatory and enforcement changes, including increased tort liability, could increase our liability if any incidents occur on our offshore operations. We cannot predict the ultimate impact the Deepwater Horizon incident and resulting changes in regulation of offshore oil and natural gas operations will have on our business or operations.

In response to the spill, and during a moratorium on deepwater (below 500 feet) drilling activities implemented between May 30, 2010 and October 12, 2010, the BOEMRE issued a series of active "Notices to Lessees and Operators", or NTLs, and adopted changes to its regulations to impose a variety of new measures intended to help prevent a similar disaster in the future.

Offshore operators, including those operating in deepwater, OCS waters and shallow waters, where we have substantial operations, must comply with strict new safety and operating requirements. For example, permit applications for drilling projects must meet new standards with respect to well design, casing and cementing, blowout preventers, safety certification, emergency response, and worker training. Operators of all offshore waters are also required to demonstrate the availability of adequate spill response and blowout containment resources. In addition, the BSEE imposed, for the first time, requirements that offshore operators maintain comprehensive safety and environmental programs. Such developments have the potential to increase our costs of doing business.

Our costs to maintain compliance with regulations applicable to our offshore operations may continue to increase.

Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS of the Gulf of Mexico and removal of facilities. Lessees subject to these regulations are generally required to have substantial net worth or post bonds or other acceptable assurances so that the various obligations of lessees on the Gulf of Mexico shelf will be met. While we have been exempt from such supplemental bonding requirements in the past, beginning in 2014 we were required to post supplemental bonding or alternate form of collateral for certain of our offshore properties. We have been able to satisfy the collateral requirements using a combination of our existing cash on hand and the issuance of supplemental bonds. However, BSEE and BOEM are currently reassessing decommissioning liability and supplemental bonding requirements for all operations on the GOM OCS with respect to decommissioning wells and platforms in the Gulf of Mexico and are updating all decommissioning costs in the Gulf of Mexico. While our cost of compliance with supplemental bonding requirements has not been material to date, based on the ongoing review of such decommissioning and abandonment costs, our potential liability for such costs has become more expensive and as a result supplemental bonding costs may continue to increase.

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

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to enhance oil and natural gas production. Hydraulic fracturing using fluids other than diesel is currently exempt from regulation under the federal Safe Drinking Water Act, but opponents of hydraulic fracturing have called for further study of the technique's environmental effects and, in some cases, a moratorium on the use of the technique. Several proposals have been submitted to Congress that, if implemented, would subject all hydraulic fracturing to regulation under the Safe Drinking Water Act. Further, the USEPA is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. The USEPA published a progress report on this study in December 2012, but has delayed release of its final draft report previously expected in 2014. The USEPA has also promulgated rules to limit air emissions from many hydraulically fractured natural gas wells. The new regulations will require use of equipment to capture gases that come from the well during the drilling process (so-called green completions). Other new requirements mandate tighter standards for emissions associated with gas production, storage and transport. Additionally, in May 2012, the BLM proposed rules to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposals, issued a revised proposal in May 2013. The revised proposal which also addresses disclosure of fluids used in the fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process, has also generated substantial public comment and no final rule has yet been promulgated.

A number of states, including Louisiana, Oklahoma and Texas, have required operators or service companies to disclose chemical components in fluids used for hydraulic fracturing. Some states have also imposed, or are considering, more stringent regulation of oil and natural gas exploration and production activities involving hydraulic fracturing by, among other things, promulgating well completion requirements, imposing controls on storage, recycling and disposal of flowback fluids, and increasing reporting obligations. In addition, concerns related to the impacts from hydraulic fracturing have led several states and locations to ban new natural gas development or to impose moratoria on use of hydraulic fracturing in various sensitive areas including some areas overlying the Marcellus Shale. Similar action could be taken to preclude or limit natural gas development in other locations.

Recent seismic events have been observed in some areas (including Oklahoma, Ohio and Texas) where hydraulic fracturing has taken place. Some scientists believe the increased seismic activity may result from deep well fluid injection associated with use of hydraulic fracturing. Additional regulatory measures designed to minimize or avoid damage to geologic formations have been imposed in states, including Ohio and Texas, to address such concerns.

Concerns regarding climate change have led the Congress, various states and environmental agencies to consider a number of initiatives to restrict or regulate emissions of greenhouse gases, such as carbon dioxide and methane. Among other things, in the absence of new federal legislation, the USEPA promulgated regulations imposing reporting and other requirements on sources of significant emissions of greenhouse gases. Stricter regulations of greenhouse gases could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, or could adversely affect demand for the oil and natural gas we produce. In addition, climate change that results in physical effects such as increased frequency and severity of storms, floods and other climatic events, could disrupt our exploration and production operations and cause us to incur significant costs in preparing for and responding to those effects.

Although it is not possible at this time to predict the final outcome of the USEPA's study or the requirements of any additional federal, state or local legislation or regulation regarding hydraulic fracturing, management of drilling fluids, well integrity requirements or climate change, any new federal or state restrictions imposed on oil and gas exploration and production activities in areas in which we conduct business could significantly increase our operating, capital and compliance costs as well as delay our ability to develop oil and natural gas reserves. In addition to increased regulation of our business, we may also experience an increase in litigation seeking damages as a result of heightened public concerns related to air quality, water quality, and other environmental impacts.

The adoption of derivatives legislation by Congress, and implementation of that legislation by federal agencies, could have an adverse impact on our ability to mitigate risks associated with our business.

On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Reform Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation required the Commodities Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the new legislation, which they have done since late 2010. The CFTC has introduced dozens of proposed rules coming out of the Dodd-Frank Reform Act, and has promulgated numerous final rules based on those proposals. The effect of the proposed rules and any additional regulations on our business is not yet entirely clear, but it is increasingly clear that the costs of derivatives-based hedging for commodities will likely increase for all market participants. Of particular concern, the Dodd-Frank Reform Act does not explicitly exempt end users from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Act to require margin from end users, the exemption is not in the Act. While rules proposed by the CFTC and federal banking regulators appear to allow for non-cash collateral and certain exemptions from margin for end users, the rules are not final and uncertainty remains. The full range of new Dodd-Frank requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to mitigate and otherwise manage our financial and commercial risks related to fluctuations in oil and natural gas prices. In addition, final rules were promulgated by the CFTC imposing federally-mandated position limits covering a wide range of derivatives positions, including non-exchange traded bilateral swaps related to commodities including oil and natural gas. These position limit rules were vacated by a Federal court in September 2012, and the CFTC has appealed that decision and could re-promulgate the rules in a manner that addresses the defects identified by the court. If these position limits rules go into effect in the future, they are likely to increase regulatory monitoring and compliance costs for all market participants, even where a given trading entity is not in danger of breaching position limits. These and other regulatory developments stemming from the Dodd-Frank Reform Act, including stringent new reporting requirements for derivatives positions and detailed criteria that must be satisfied to continue to enter into uncleared swap transactions, could have a material impact on our derivatives trading and hedging activities in the form of increased transaction costs and compliance responsibilities. Any of the foregoing consequences could have a material adverse effect on our financial position, results of operations and cash flows.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

From time to time legislative proposals are made that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included, among others, eliminating the immediate deduction for intangible drilling and development costs, eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, repealing the percentage depletion allowance for oil and natural gas properties and extending the amortization period for certain geological and geophysical expenditures. Such proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

We face strong competition from larger oil and natural gas companies that may negatively affect our ability to carry on operations.

We operate in the highly competitive areas of oil and natural gas exploration, development and production. Factors that affect our ability to compete successfully in the marketplace include:

- the availability of funds and information relating to a property;
- the standards established by us for the minimum projected return on investment; and
- the transportation of natural gas.

Our competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local natural gas gatherers, many of which possess greater financial and other resources than we do. If we are unable to successfully compete against our competitors, our business, prospects, financial condition and results of operations may be adversely affected.

Operating hazards may adversely affect our ability to conduct business.

Our operations are subject to risks inherent in the oil and natural gas industry, such as:

- unexpected drilling conditions including blowouts, cratering and explosions;

- uncontrollable flows of oil, natural gas or well fluids;
- equipment failures, fires or accidents;
- pollution and other environmental risks; and
- shortages in experienced labor or shortages or delays in the delivery of equipment.

These risks could result in substantial losses to us from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

Environmental compliance costs and environmental liabilities could have a material adverse effect on our financial condition and operations.

Our operations are subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The trend toward stricter requirements and standards in environmental legislation and regulation is likely to continue. Our drilling plans may be delayed, modified or precluded as a result of new or modified environmental mandates, including those imposed to protect the American Burying Beetle and other endangered species that may be present in the vicinity of our operations. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and natural gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages, but this insurance may not extend to the full potential liability that could be caused by sudden and accidental environmental damages and further may not cover environmental damages that occur over time. Accordingly, we may be subject to liability or may lose the ability to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

We cannot control the activities on properties we do not operate and we are unable to ensure the proper operation and profitability of these non-operated properties.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of drilling and development activities on our partially owned properties operated by others therefore will depend upon a number of factors outside of our control, including the operator's:

- timing and amount of capital expenditures;
- expertise and diligence in adequately performing operations and complying with applicable agreements;
- financial resources;
- inclusion of other participants in drilling wells; and

- use of technology.

As a result of any of the above or an operator's failure to act in ways that are in our best interest, our allocated production revenues and results of operations could be adversely affected.

Ownership of working interests and overriding royalty interests in certain of our properties by certain of our officers and directors potentially creates conflicts of interest.

Certain of our executive officers and directors or their respective affiliates are working interest owners or overriding royalty interest owners in certain properties. In their capacity as working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners they are entitled to receive their proportionate share of revenues in the normal course of business. There is a potential conflict of interest between us and such officers and directors with respect to the drilling of additional wells or other development operations with respect to these properties.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Relating to Our Outstanding Common Stock

Our stock price could be volatile, which could cause you to lose part or all of your investment.

The stock market has from time to time experienced significant price and volume fluctuations that may be unrelated to the operating performance of particular companies. In particular, the market price of our common stock, like that of the securities of other energy companies, has been and may continue to be highly volatile. During 2014, the sales price of our stock ranged from a low of $3.15 per share (on December 15, 2014) to a high of $7.82 per share (on June 30, 2014). Factors such as announcements concerning changes in prices of oil and natural gas, the success of our acquisition, exploration and development activities, the availability of capital, and economic and other external factors, as well as period-to-period fluctuations and financial results, may have a significant effect on the market price of our common stock.

From time to time, there has been limited trading volume in our common stock. In addition, there can be no assurance that there will continue to be a trading market or that any securities research analysts will continue to provide research coverage with respect to our common stock. It is possible that such factors will adversely affect the market for our common stock.

Issuance of shares in connection with financing transactions or under stock incentive plans will dilute current stockholders.

We have issued 1,495,000 shares of Series B Preferred Stock, which are presently convertible into 5,147,734 shares of our common stock. In addition, pursuant to our stock incentive plan, our management is authorized to grant stock awards to our employees, directors and consultants. You will incur dilution upon the conversion of the Series B Preferred Stock, the exercise of any outstanding stock awards or the grant of any restricted stock. In addition, if we raise additional funds by issuing additional common stock, or securities convertible into or exchangeable or exercisable for common stock, further dilution to our existing stockholders will result, and new investors could have rights superior to existing stockholders.

The number of shares of our common stock eligible for future sale could adversely affect the market price of our stock.

At December 31, 2014, we had reserved approximately 1.5 million shares of common stock for issuance under outstanding options and approximately 5.1 million shares issuable upon conversion of the Series B Preferred Stock. All of these shares of common stock are registered for sale or resale on currently effective registration statements. We may issue additional restricted securities or register additional shares of common stock under the Securities Act in the future. The issuance of a significant number of shares of common stock upon the exercise of stock options, the granting of restricted stock or the conversion of the Series B Preferred Stock, or the availability for sale, or sale, of a substantial number of the shares of our common stock eligible for future sale under effective registration statements, under Rule 144 or otherwise, could adversely affect the market price of the common stock.

Provisions in our certificate of incorporation and bylaws could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders.

Certain provisions of our certificate of incorporation and bylaws may delay, discourage, prevent or render more difficult an attempt to obtain control of our company, whether through a tender offer, business combination, proxy contest or otherwise. These provisions include:

- the charter authorization of “blank check” preferred stock;
- provisions that directors may be removed only for cause, and then only on approval of holders of a majority of the outstanding voting stock;
- a restriction on the ability of stockholders to call a special meeting and take actions by written consent; and
- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders.

We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted.

We have not paid dividends on our common stock, in cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. We are currently restricted from paying dividends on our common stock by our bank credit facility, the indenture governing the 10% senior notes and, in some circumstances, by the terms of our Series B Preferred Stock. Any future dividends also may be restricted by our then-existing debt agreements.

Item 1B **Unresolved Staff Comments**

None

Item 3. **Legal Proceedings**

PetroQuest is involved in litigation relating to claims arising out of its operations in the normal course of business, including worker’s compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. Management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on PetroQuest’s business or financial position.

Item 4. **Mine Safety Disclosures**

Not applicable.

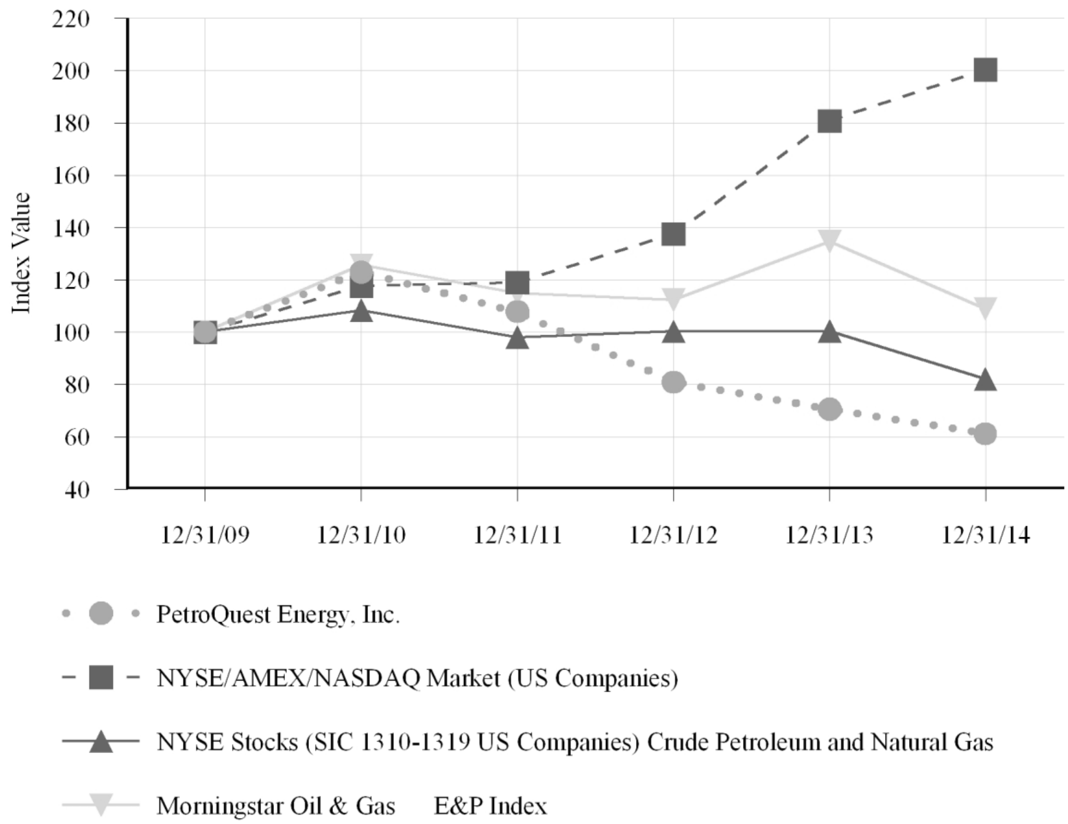
PART II

Item 5.

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

The following graph illustrates the yearly percentage change in the cumulative stockholder return on our common stock, compared with the cumulative total return on the NYSE/AMEX Stock Market (U.S. Companies) Index, the NYSE Stocks—Crude Petroleum and Natural Gas Index and the Morningstar Oil and Gas E&P Index, for the five years ended December 31, 2014.

Comparison of 5 Year Cumulative Total Return
Assumes Initial Investment of $100
December 31, 2014



	PetroQuest Energy, Inc.	NYSE/AMEX/NASDAQ Market (US Companies)	NYSE Stocks (SIC 1310-1319 US Companies) Crude Petroleum and Natural Gas	Morningstar Oil & Gas E&P Index
12/31/2009	$100.00	$100.00	$100.00	$100.00
12/31/2010	122.84	117.68	108.32	125.54
12/31/2011	107.67	118.91	97.92	114.79
12/31/2012	80.75	137.50	100.19	112.29
12/31/2013	70.47	180.77	100.26	134.57
12/31/2014	61.01	200.34	82.04	108.84

Market Price of and Dividends on Common Stock

Our common stock trades on the New York Stock Exchange under the symbol "PQ." The following table lists high and low sales prices per share for the periods indicated:

2013		High		Low
1st Quarter	$	5.39	$	3.55
2nd Quarter		5.10		3.85
3rd Quarter		4.74		3.87
4th Quarter		4.93		3.63
2014				
1st Quarter	$	5.93	$	3.66
2nd Quarter		7.82		5.17
3rd Quarter		7.76		5.13
4th Quarter		5.66		3.15

As of February 26, 2015, there were 272 common stockholders of record.

We have never paid a dividend on our common stock, cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. In addition, under our bank credit facility, the indenture governing the 10% senior notes, and, in some circumstances, the terms of our Series B Preferred Stock, we are restricted from paying cash dividends on our common stock. The payment of future dividends, if any, will be determined by our Board of Directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. See Item 1A. "Risk Factors – Risks Relating to our Outstanding Common Stock – We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted."

The following table sets forth certain information with respect to repurchases of our common stock during the quarter ended December 31, 2014.

	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan or Program	Maximum Number (or Approximate Dollar Value) of Shares that May be Purchased Under the Plans or Programs
October 1—October 31, 2014	17,979	$ 4.53	—	—
November 1—November 30, 2014	155,730	$ 4.01	—	—
December 1—December 31, 2014	5,091	$ 3.82	—	—

(1) All shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards.

Item 6. **Selected Financial Data**

The following table sets forth, as of the dates and for the periods indicated, selected financial information for the Company. The financial information for each of the five years in the period ended December 31, 2014 has been derived from the audited Consolidated Financial Statements of the Company for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and notes thereto. The following information is not necessarily indicative of future results of the Company. All amounts are stated in U.S. dollars unless otherwise indicated.

	Year Ended December 31,				
	2014	2013	2012 (1)	2011 (2)	2010
	(in thousands except per share and per Mcfe data)				
Average sales price per Mcfe	$ 5.19	$ 4.80	$ 4.17	$ 5.32	$ 5.78
Revenues	225,021	182,804	141,433	160,486	179,038
Net income (loss) available to common stockholders	26,051	8,943	(137,218)	5,409	41,987
Net income (loss) available to common stockholders per share:					
Basic	0.39	0.14	(2.20)	0.08	0.67
Diluted	0.39	0.14	(2.20)	0.08	0.66
Oil and gas properties, net	683,812	581,242	333,946	405,351	312,940
Total assets	790,895	667,190	433,403	516,166	439,517
Long-term debt	425,000	425,000	200,000	150,000	150,000
Stockholders' equity	136,909	99,095	87,591	222,390	208,162

(1) The year ended December 31, 2012 includes a pre-tax ceiling test write-down of $137.1 million.
(2) The year ended December 31, 2011 includes a pre-tax ceiling test write-down of $18.9 million.

Item 7.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with primary operations in Oklahoma, Texas, and the Gulf Coast Basin. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations in 1985 through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins.

We have successfully diversified into onshore, longer life basins in Oklahoma and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in Texas through 2014, we have invested a majority of our capital into growing our longer life assets. During the eleven year period ended December 31, 2014, we have realized a 94% drilling success rate on 976 gross wells drilled. Comparing 2014 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 348% and estimated proved reserves by 377%. At December 31, 2014, 86% of our estimated proved reserves and 62% of our 2014 production were derived from our longer life assets.

We are focused on growing our reserves and production through a balanced drilling budget with an increased emphasis on growing our oil and natural gas liquids production. In May 2010, we entered into the JDA, which provided us with $85 million in cash during 2010 and 2011, along with a drilling carry that we have utilized since May 2010 to enhance economic returns by reducing our share of capital expenditures primarily in the Woodford Shale.

During 2013, we closed the Gulf of Mexico Acquisition (discussed below) which significantly enhanced our production. Utilizing the free cash flow provided by these acquired assets, we launched expanded drilling programs during 2014 in East Texas and the liquids rich portion of the Woodford Shale. The success of these two drilling programs, combined with a significant discovery at our Thunder Bayou prospect in the Gulf Coast Basin, were key components enabling us to achieve record production and record annual year end reserves during 2014.

In response to the impact that the decline in commodity prices has had on our cash flow, our 2015 capital expenditures will be significantly reduced as compared to 2014. Our 2015 capital expenditures, which include capitalized interest and overhead but exclude acquisitions, are expected to range between $60 million and $70 million and are expected to be funded through cash flow from operations and cash on hand. To the extent our capital expenditures during 2015 exceed our cash flow from operations and cash on hand, we plan to utilize available borrowings under our bank credit facility. Because we operate approximately 88% of our total estimated proved reserves and manage the drilling and completion activities on an additional 6% of such reserves, we expect to be able to control the timing of a substantial portion of our capital investments. We also plan to maintain our commodity hedging program and, as in during prior years, we may continue to opportunistically dispose of certain assets to provide additional liquidity. During December 2012, we sold our non-operated Arkansas assets for $8.5 million. During January 2013, we sold 50% of our saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10 million. During December 2013, we sold our non-operated Wyoming assets for $1.0 million. In September 2014, we sold our Eagle Ford assets for net proceeds of approximately $9.8 million.

Gulf of Mexico Acquisition

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million, reflecting an effective date of January 1, 2013. The Gulf of Mexico Acquisition was financed with the issuance of an additional $200 million in aggregate principal amount of our 10% Senior Notes due 2017. The acquired assets included 16 gross wells located on seven platforms.

The Gulf of Mexico Acquisition added 30.5 Bcfe of estimated proved reserves as of December 31, 2013 and increased our net acreage position in the Gulf Coast Basin by 23%. The acquired assets contributed 8.4 Bcfe and 4.5 Bcfe of total production, including 459,000 barrels and 235,000 barrels of oil, during 2014 and 2013, respectively. See "Note 2 - Acquisition" in Item 8. Financial Statements and Supplementary Data for additional details related to this transaction.

Fleetwood Joint Venture

In June 2014, we entered into a joint venture in Louisiana for an aggregate purchase price of $24 million. The assets acquired under the joint venture include an average 37% working interest in an approximately 30,000 acre leasehold position in Louisiana and exclusive rights, along with our joint venture partner, to a 200 square mile proprietary 3D survey which has generated several conventional and shallow non-conventional oil focused prospects.

The purchase price was comprised of $10 million in cash and $14 million in cash funding for future drilling, completion and lease acquisition costs. If the $14 million in drilling, completion and lease acquisition costs is not fully funded by December 31, 2015, any remaining balance becomes payable at the election of our joint venture partner. At December 31, 2014, $7 million of cash purchase price and $10.7 million of drilling carry remained outstanding. The $7 million of cash purchase price was paid in January 2015.

Critical Accounting Policies

Reserve Estimates

Our estimates of proved oil and gas reserves constitute those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. At the end of each year, our proved reserves are estimated by independent petroleum engineers in accordance with guidelines established by the SEC. These estimates, however, represent projections based on geologic and engineering data. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quantity and quality of available data, engineering and geological interpretation and professional judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of such oil and gas properties.

Disclosure requirements under Staff Accounting Bulletin 113 ("SAB 113") include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. Pricing is based on a 12-month average price using beginning of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves. In addition, the 12-month average is also used to measure ceiling test impairments and to compute depreciation, depletion and amortization.

Full Cost Method of Accounting

We use the full cost method of accounting for our investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress and geological and geophysical service costs in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and 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 gas.

The costs associated with unevaluated properties are not initially included in the amortization base and primarily relate to ongoing exploration activities, unevaluated leasehold acreage and delay rentals, seismic data and capitalized interest. These costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value.

We compute the provision for depletion of oil and gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs related to non-producing reserves. Our depletion expense is affected by the estimates of future development costs, unevaluated costs and proved reserves, and changes in these estimates could have an impact on our future earnings.

We capitalize certain internal costs that are directly identified with acquisition, exploration and development activities. The capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. We also capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated properties and our effective borrowing rate.

Capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization ("DD&A") and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effect of cash flow hedges in place, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of oil and gas properties in the quarter in which the excess occurs.

Given the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from estimated proved oil and gas reserves will change in the near term. If oil or gas prices remain at current levels or decline further, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of oil and gas properties could occur in the future.

Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology, the timing of estimated costs, the impact of future inflation on current cost estimates and the political and regulatory environment.

Derivative Instruments

We seek to reduce our exposure to commodity price volatility by hedging a portion of our production through commodity derivative instruments. The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. The changes in fair value of those derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil or natural gas quantities are produced. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income (expense).

Our hedges are specifically referenced to NYMEX prices for oil and natural gas and OPIS Mt. Bellevue pricing for natural gas liquids. We evaluate the effectiveness of our hedges at the time we enter the contracts, and periodically over the life of the contracts, by analyzing the correlation between NYMEX and OPIS Mt. Bellevue prices and the posted prices we receive from our designated production. Through this analysis, we are able to determine if a high correlation exists between the prices received for the designated production and the NYMEX and OPIS Mt. Bellevue prices at which the hedges will be settled. At December 31, 2014, our derivative instruments were designated effective cash flow hedges.

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX and OPIS Mt. Bellevue prices, discount rates and price movements. As a result, we calculate the fair value of our commodity derivatives using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. Our fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of our default risk for derivative liabilities.

Results of Operations

The following table sets forth certain information with respect to our oil and gas operations for the periods noted. These historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,		
	2014	2013	2012
Production:			
Oil (Bbls)	802,509	680,980	520,590
Gas (Mcf)	31,027,671	29,225,843	27,466,228
Ngl (Mcfe)	7,482,310	4,754,223	3,366,774
Total Production (Mcfe)	43,325,035	38,065,946	33,956,542
Sales:			
Total oil sales	$ 78,176,377	$ 70,476,065	$ 56,635,786
Total gas sales	114,613,267	87,449,370	63,535,262
Total ngl sales	32,231,090	24,878,243	21,262,236
Total oil and gas sales	$ 225,020,734	$ 182,803,678	$ 141,433,284
Average sales prices:			
Oil (per Bbl)	$ 97.41	$ 103.49	$ 108.79
Gas (per Mcf)	3.69	2.99	2.31
Ngl (per Mcfe)	4.31	5.23	6.32
Per Mcfe	5.19	4.80	4.17

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of ($4,237,000), $1,098,000 and $6,846,000, oil hedges of $897,000, ($232,000) and $1,529,000, and Ngl hedges of $296,000, $61,000 and $722,000 for the twelve months ended December 31, 2014, 2013 and 2012, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2014 and 2013

Net income available to common stockholders totaled $26,051,000 and $8,943,000 for the years ended December 31, 2014 and 2013, respectively. The primary fluctuations were as follows:

Production Total production increased 14% during the year ended December 31, 2014 as compared to the 2013 period. The increase in total production was due primarily to a full year of production from the wells acquired in the Gulf of Mexico Acquisition, which closed on July 3, 2013, as well as our successful drilling programs in our Carthage field and the liquids rich portion of our Oklahoma acreage position. Partially offsetting these increases were decreases in production due to normal production declines at our dry gas Oklahoma fields as well as certain of our legacy Gulf Coast fields. As a result of the current low commodity price environment and our intention to fund our 2015 drilling activities with cash flows from operations, our 2015 capital expenditures budget will be significantly lower as compared to 2014. Despite the substantial decrease in capital spending, we expect our total production in 2015 to increase as compared to 2014 as a result of our continued drilling programs in our Oklahoma and Carthage fields, as well as anticipated initial production from our Thunder Bayou discovery in 2015.

Gas production during the year ended December 31, 2014 increased 6% from the 2013 period. The increase in gas production was due primarily to our successful drilling program in our Carthage field as well as a full year of production from the wells acquired in the Gulf of Mexico Acquisition. Partially offsetting these increases were decreases in gas production due to normal production declines at our dry gas Oklahoma fields as well as certain of our legacy Gulf Coast fields. As a result of continued drilling efforts in our Oklahoma and Carthage fields, as well as anticipated production from the completion of our Thunder Bayou discovery, we expect our average daily gas production to increase during 2015 as compared to 2014.

Oil production during the year ended December 31, 2014 increased 18% as compared to the 2013 period due primarily to a full year of production from the wells acquired in the Gulf of Mexico Acquisition. Partially offsetting this increase were decreases as a result of continued normal production declines in certain of our legacy Gulf Coast fields. As a result of normal production declines at certain of our legacy Gulf Coast fields, we expect our average daily oil production to decrease during 2015 as compared to 2014.

Ngl production during the year ended December 31, 2014 increased 57% from the 2013 period due to the successful drilling programs in the liquids rich portion of our Oklahoma acreage position and in our Carthage field. Additionally, Ngl production increased as a result of added production from the wells acquired in the Gulf of Mexico Acquisition. Partially offsetting these increases were decreases as a result of normal production declines at our legacy Gulf Coast fields. As a result of the decrease in drilling activity planned for our liquids rich Oklahoma and Carthage acreage in 2015, as well as our expectation that we will not be recovering ethane volumes in Oklahoma due to the low ethane pricing environment, we expect our daily Ngl production for 2015 to decrease compared to that of 2014.

Prices Including the effects of our hedges, average gas prices per Mcf for the year ended December 31, 2014 were $3.69 as compared to $2.99 for the 2013 period. Average oil prices per Bbl for the year ended December 31, 2014 were $97.41 as compared to $103.49 for the 2013 period and average Ngl prices per Mcfe were $4.31 for the year ended December 31, 2014, as compared to $5.23 for the 2013 period. Stated on an Mcfe basis, unit prices received during the year ended December 31, 2014 were 8% higher than the prices received during the 2013 period. We expect 2015 average realized prices received to decrease as compared to 2014.

Revenue Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2014 increased 23% to $225,021,000, as compared to oil and gas sales of $182,804,000 during the 2013 period. The increased revenue during 2014 was primarily the result of increased production during 2014 as well as higher average realized prices for our gas production, which represents the majority of our total production.

Expenses Lease operating expenses for the year ended December 31, 2014 totaled $48,597,000, or $1.12 per Mcfe, as compared to $43,743,000, or $1.15 per Mcfe, during the 2013 period. The decrease in per unit lease operating expenses for the year ended December 31, 2014 is primarily due to increased production from our onshore properties which typically incur lower per unit lease operating expenses. We expect lease operating expenses during 2015 to approximate 2014 expenses, both on an absolute value and on a per unit basis.

Production taxes for the year ended December 31, 2014 totaled $5,927,000, or $0.14 per Mcfe, as compared to $3,950,000, or $0.10 per Mcfe, during the 2013 period. The increase in total production taxes was primarily due to increased production from onshore properties subject to severance taxes as well as an increase in Louisiana severance tax rates effective July 2014. The majority of our properties that are subject to severance taxes are assessed on the oil and gas sales value. As a result of the current commodity pricing environment, we expect a decrease in our total and per unit production taxes during 2015 as compared to 2014.

General and administrative expenses during the year ended December 31, 2014 totaled $22,870,000 as compared to $26,512,000 during the 2013 period. General and administrative expenses decreased 14% during the year ended December 31, 2014 primarily due to acquisition-related costs associated with the Gulf of Mexico Acquisition of $4,018,000 incurred during the 2013 period. Included in general and administrative expenses for 2014 are share-based compensation costs, net of amounts capitalized, of $6,808,000, compared to $5,011,000 during the 2013 period. We capitalized $12,122,000 of general and administrative costs during the year ended December 31, 2014 as compared to $13,342,000 during the comparable 2013 period. We expect general and administrative expenses to decrease further in 2015.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the year ended December 31, 2014 totaled $86,406,000, or $1.99 per Mcfe, as compared to $69,357,000, or $1.82 per Mcfe, during the comparable 2013 period. The increase in the per unit DD&A rate is primarily the result of the properties acquired in the Gulf of Mexico Acquisition, which had a higher cost per unit as compared to our overall amortization base. As a result of our significant increase in estimated proved reserves at December 31, 2014, we expect our DD&A rate for 2015 to be significantly lower than the rate during 2014.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $29,281,000 during the year ended December 31, 2014, as compared to $21,886,000 during 2013. During the year ended December 31, 2014, our capitalized interest totaled $9,999,000 as compared to $6,570,000 during the 2013 period. The increase in interest expense was a result of the issuance of an additional $200 million of 10% senior notes in 2013, which were used to finance the Gulf of Mexico Acquisition. We expect interest expense for 2015 to approximate interest expense in 2014.

Income tax expense (benefit) during the year ended December 31, 2014 totaled ($2,941,000), as compared to $320,000 during the 2013 period. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

As a result of the ceiling test write-downs recognized during 2012, we have incurred a cumulative three-year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, we assessed the realizability of our deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, we established a valuation allowance for a portion of our deferred tax asset. The valuation allowance was $33,295,000 as of December 31, 2014.

Comparison of Results of Operations for the Years Ended December 31, 2013 and 2012

Net income (loss) available to common stockholders totaled $8,943,000 and ($137,218,000) for the years ended December 31, 2013 and 2012, respectively. The primary fluctuations were as follows:

Production Total production increased 12% during the year ended December 31, 2013 as compared to the 2012 period. Gas production during the year ended December 31, 2013 increased 6% from the 2012 period. The increase in gas production was primarily the result of added production from the Gulf of Mexico Acquisition, which closed on July 3, 2013. Additionally, gas production increased as a result of the successful drilling programs in our La Cantera field and our liquids rich Woodford acreage. Partially offsetting these increases were decreases in gas production due to normal production declines at our dry gas Oklahoma fields as well as certain of our legacy Gulf of Mexico fields in addition to the loss of production resulting from the sale of our Fayetteville assets in December 2012.

Oil production during the year ended December 31, 2013 increased 31% as compared to the 2012 period due primarily to added production from the Gulf of Mexico Acquisition as well as the continued success of our La Cantera field. Partially offsetting these increases were decreases as a result of continued normal production declines in certain of our legacy Gulf of Mexico and East Texas fields.

Ngl production during the year ended December 31, 2013 increased 41% from the 2012 period due to the success experienced in our La Cantera field and the liquids rich portion of our Oklahoma properties, as well as added production from the Gulf of Mexico Acquisition. Partially offsetting these increases were decreases as a result of normal production declines at certain of our legacy Gulf of Mexico fields.

Prices Including the effects of our hedges, average gas prices per Mcf for the year ended December 31, 2013 were $2.99 as compared to $2.31 for the 2012 period. Average oil prices per Bbl for the year ended December 31, 2013 were $103.49 as compared to $108.79 for the 2012 period and average Ngl prices per Mcfe were $5.23 for the year ended December 31, 2013, as compared to $6.32 for the 2012 period. Stated on an Mcfe basis, unit prices received during the year ended December 31, 2013 were 15% higher than the prices received during the 2012 period.

Revenue Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2013 increased 29% to $182,804,000, as compared to oil and gas sales of $141,433,000 during the 2012 period. The increased revenue during 2013 was primarily the result of higher average realized prices for our production during 2013 as well as increased production as discussed above.

Expenses Lease operating expenses for the year ended December 31, 2013 totaled $43,743,000 as compared to $38,890,000 during the 2012 period. Per unit lease operating expenses totaled $1.15 per Mcfe during both of the years ended December 31, 2013 and 2012.

Production taxes for the year ended December 31, 2013 totaled $3,950,000, or $0.10 per Mcfe, as compared to $885,000, or $0.03 per Mcfe, during the 2012 period. The significant reduction during the 2012 period was the result of recording a receivable of

$2,717,000 during June 2012 for refunds relative to severance tax previously paid on our Oklahoma horizontal wells for which we are receiving payments incrementally through June 2015.

General and administrative expenses during the year ended December 31, 2013 totaled $26,512,000 as compared to $22,957,000 during the 2012 period. General and administrative expenses increased 15% during the year ended December 31, 2013 as compared to the 2012 period. Included in general and administrative expenses during the 2013 period is $4,018,000 of acquisition-related costs related to the Gulf of Mexico Acquisition. In addition, during 2013, we recognized approximately $895,000 in general and administrative expenses associated with benefits due under the compensation agreements of the Company's Executive Vice-President and General Counsel, who passed away unexpectedly in September 2013. Included in general and administrative expenses for 2013 are share-based compensation costs, net of amounts capitalized, of $5,011,000, compared to $7,057,000 during the 2012 period. We capitalized $13,342,000 of general and administrative costs during the year ended December 31, 2013 as compared to $11,925,000 during the comparable 2012 period.

DD&A expense on oil and gas properties for the year ended December 31, 2013 totaled $69,357,000, or $1.82 per Mcfe, as compared to $59,496,000, or $1.75 per Mcfe, during the comparable 2012 period. The increase in the per unit DD&A rate is primarily the result of the Gulf of Mexico Acquisition, which had a higher cost per unit as compared to our overall amortization base.

At December 31, 2012, the prices used in computing the estimated future net cash flows from our estimated proved reserves, including the effect of hedges in place at that date, averaged $2.21 per Mcf of natural gas, $102.81 per barrel of oil, and $6.07 per Mcfe of Ngl. As a result of lower natural gas prices and their negative impact on certain of our longer-lived estimated proved reserves and estimated future net cash flows, we recognized ceiling test write-downs of $137,100,000 during the year ended December 31, 2012. No such ceiling test write-down occurred during 2013.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $21,886,000 during the year ended December 31, 2013, as compared to $9,808,000 during 2012. During the year ended December 31, 2013, our capitalized interest totaled $6,570,000 as compared to $7,036,000 during the 2012 period. The increase in interest expense was a result of the issuance of an additional $200 million of 10% senior notes, which were used to finance the Gulf of Mexico Acquisition in addition to increased borrowings outstanding under our bank credit facility during 2013 as compared to 2012.

Income tax expense during the year ended December 31, 2013 totaled $320,000, as compared to $1,636,000 during the 2012 period. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

As a result of the ceiling test write-downs recognized during 2012, we have incurred a cumulative three-year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, we assessed the realizability of our deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, we established a valuation allowance for a portion of our deferred tax asset. The valuation allowance was $45,531,000 as of December 31, 2013.

Liquidity and Capital Resources

We have financed our acquisition, exploration and development activities to date principally through cash flow from operations, bank borrowings, issuances of equity and debt securities, joint ventures and sales of assets. At December 31, 2014, we had a working capital deficit of $80.2 million compared to a deficit of $26.1 million at December 31, 2013. The increase in our working capital deficit is primarily due to the timing of our accounts payable as a result of an increase in operational activity during 2014, and to a lesser extent our Fleetwood joint venture. Since we operate the majority of our drilling activities, we have the ability to reduce our capital expenditures to manage our working capital deficit and liquidity position. In response to the impact that the decline in commodity prices has had, and is expected to continue to have, on our cash flow, our 2015 capital expenditures are significantly reduced as compared to 2014 and are planned to be funded through cash flow from operations and cash on hand. To the extent our capital expenditures during 2015 exceed our cash flow from operations and cash on hand, we plan to utilize available borrowings under the bank credit facility or proceeds from the potential sale of certain assets to fund a portion of our drilling budget.

Prices for oil and natural gas are subject to many factors beyond our control such as weather, the overall condition of the global financial markets and economies, relatively minor changes in the outlook of supply and demand, and the actions of OPEC. Oil and natural gas prices have a significant impact on our cash flows available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our bank credit facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the bank credit facility, thus reducing the amount of financial resources available to meet our capital requirements. Lower prices and reduced cash flow may also make it difficult to incur debt, including under our bank credit facility, because of the restrictive covenants in the indenture governing the Notes. See "Source of Capital: Debt" below. Our ability to comply with the covenants in our debt agreements is dependent upon the success of our exploration and development program and upon factors beyond our control, such as oil and natural gas prices.

Source of Capital: Operations

Net cash flow from operations increased from $59.9 million during the year ended December 31, 2013 to $178.2 million during the 2014 period. The increase in operating cash flow during 2014 as compared to 2013 was primarily attributable to increases in oil and gas revenues as well as the timing of payment of payables and receipt of advances from co-owners based on increased operational activity.

Source of Capital: Debt

On August 19, 2010, we issued $150 million in principal amount of 10% Senior Notes due 2017 (the "Existing Notes"). On July 3, 2013, we issued an additional $200 million in principal amount of 10% Senior Notes due 2017 (the "New Notes" and together with the Existing Notes, the "Notes"). The New Notes were issued at a price equal to 100% of their face value plus accrued interest from March 1, 2013, and are substantially identical to the Existing Notes. The net proceeds from the offering were used to finance the $188.8 million aggregate cash purchase price of the Gulf of Mexico Acquisition, which also closed on July 3, 2013.

The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on March 1 and September 1. At December 31, 2014, $11.7 million of interest had been accrued in connection with the March 1, 2015 interest payment and we were in compliance with all of the covenants contained in the Notes.

We have a Credit Agreement (as amended, the "Credit Agreement" and sometimes referred to elsewhere in this Form 10-K as our "bank credit facility") with JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IberiaBank, Bank of America, N.A. and The Bank of Nova Scotia (collectively the "Lenders"). The Credit Agreement provides us with a $300 million revolving credit facility that permits borrowings based on the commitments of the Lenders and the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows us to use up to $25 million of the borrowing base for letters of credit. Our bank credit facility matures on October 3, 2016. As of December 31, 2014, we had $75.0 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation of the reserves attributable to our oil and gas properties as of January 1 and July 1 of each year. In connection with the most recent redetermination, the borrowing base was increased to $220 million (subject to the aggregate commitments of the lenders then in effect) effective September 30, 2014. As of December 31, 2014, the aggregate commitments of the Lenders is $170 million and can be increased to up to $300 million by either adding new lenders or increasing the commitments of existing Lenders, subject to certain conditions.

The next borrowing base redetermination is scheduled to occur by March 31, 2015. We or the Lenders may request two additional borrowing base re-determinations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all Lenders if the borrowing base is to be increased, or by Lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The Credit Agreement is secured by a first priority lien on substantially all of our assets, including a lien on all equipment and at least 80% of the aggregate total value of our oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 0.5% to 1.5% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.5% depending on total commitments). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate plus 1%. For the purposes of the definition of alternate base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by us) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, we pay commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

We are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.5 to 1.0, and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0, all as defined in the Credit Agreement. The Credit Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. However, the Credit Agreement permits us to repurchase up to $10 million of our common stock during the term of the Credit Agreement, as long as after giving effect to such repurchase our Liquidity (as defined therein) is greater than 20% of the total commitments of the Lenders at such time. As of December 31, 2014, we were in compliance with all of the covenants contained in the Credit Agreement.

During February 2015, the Company and the Lenders amended the Credit Agreement in order to modify certain restrictive financial covenants. Specifically, the amendment removed the 3.5 to 1.0 maximum ratio of total debt to EBITDAX and replaced that with a maximum ratio of total senior secured debt to EBITDAX, determined on a rolling four quarter basis, not to exceed 2.25 to 1.0. In addition, the amendment added a minimum ratio of EBITDAX to total cash interest expense, determined on a rolling four quarter basis, of 2.0 to 1.0. The modification to the covenants described above will become effective with the quarter ended March 31, 2015 and will remain in effect through the Credit Agreement's maturity in October 2016.

Source of Capital: Issuance of Securities

Our shelf registration statement allows us to publicly offer and sell up to $350 million of any combination of debt securities, shares of common and preferred stock, depositary shares and warrants. The registration statement does not provide any assurance that we will or could sell any such securities.

Source of Capital: Joint Ventures

In May 2010, we entered into a joint development agreement with WSGP Gas Producing, LLC ("WSGP"), a subsidiary of NextEra Energy Resources, LLC, whereby WSGP acquired approximately 29 Bcfe of our Woodford proved undeveloped reserves as well as the right to earn 50% of our undeveloped Woodford acreage position through a two phase drilling program. We received approximately $57.4 million in cash at closing, net of $2.6 million in transaction fees, and an additional $14 million in each of 2011 and 2012. In addition, since May 2010, WSGP has funded a share of our drilling costs under a drilling program, which we refer to as the drilling carry. As of December 31, 2014, approximately $25.8 million of drilling carry remained available.

Source of Capital: Divestitures

We do not budget property divestitures; however, we are continuously evaluating our property base to determine if there are assets in our portfolio that no longer meet our strategic objectives. From time to time we may divest certain assets in order to provide liquidity to strengthen our balance sheet or provide capital to be reinvested in higher rate of return projects. We are currently exploring divestment opportunities for our Mississippian Lime assets. We cannot assure you that we will be able to sell any of our assets in the future.

On December 31, 2012, we sold our non-operated Arkansas assets for a net cash purchase price of $8.5 million. In January 2013, we sold 50% of our saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10 million. In December 2013, we sold our non-operated Wyoming assets for a cash purchase price of $1.0 million. In September 2014, we sold our Eagle Ford assets for net proceeds of approximately $9.8 million.

Use of Capital: Exploration and Development

Our 2015 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between $60 million and $70 million, which represents a 67% reduction from our 2014 capital expenditures in response to weaker commodity prices. Because we operate the majority of our drilling activities, we expect to be able to control the timing of a substantial portion of our capital investments. We plan to fund our capital expenditures with cash flow from operations and cash on hand. To the extent our capital expenditures during 2015 exceed our cash flow from operations and cash on hand, we plan to utilize available borrowings under the bank credit facility or proceeds from the potential sale of certain assets. To the extent additional capital is required, we may utilize sales of equity or debt securities or we may reduce our capital expenditures to manage our liquidity position.

Use of Capital: Acquisitions

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million. The acquired assets include 16 gross wells located on seven platforms.

We do not budget acquisitions; however, we are continuously evaluating opportunities to expand our existing asset base or establish positions in new core areas.

We expect to finance our future acquisition activities, if consummated, through cash on hand or available borrowings under our bank credit facility. We may also utilize sales of equity or debt securities, sales of properties or assets or joint venture arrangements with industry partners, if necessary. We cannot assure you that such additional financings will be available on acceptable terms, if at all.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2014 (in thousands):

	Total	2015	2016	2017	2018	2019	After 2019
10% senior notes (1)	$ 446,250	$ 35,000	$ 35,000	$ 376,250	$ —	$ —	$ —
Credit Agreement debt (1)	77,879	1,559	76,320	—	—	—	—
Operating leases (2)	6,663	1,480	1,418	1,317	416	401	1,631
Asset retirement obligations (3)	54,970	2,756	4,305	4,201	59	737	42,912
Purchase commitments (4)	8,577	8,577	—	—	—	—	—
Acquisition Costs (5)	17,690	17,690	—	—	—	—	—
Firm Transportation Agreements (6)	1,815	770	1,045	—	—	—	—
Total	$ 613,844	$ 67,832	$ 118,088	$ 381,768	$ 475	$ 1,138	$ 44,543

(1) Includes principal and estimated interest.
(2) Consists primarily of leases for office space and office equipment.
(3) Consists of estimated future obligations to abandon our oil and gas properties.
(4) Consists of certain drilling rig and seismic contracts.
(5) Consists of amounts payable related to the Fleetwood Joint Venture
(6) Consists of firm transportation costs related to our Mississippian Lime acreage

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

We experience market risks primarily in two areas: interest rates and commodity prices. Because all of our properties are located within the United States, we believe that our business operations are not exposed to significant market risks relating to foreign currency exchange risk.

Our revenues are derived from the sale of our crude oil, natural gas, and natural gas liquids production. Based on projected annual sales volumes for 2015, a 10% decline in the estimated average prices we expect to receive for our crude oil, natural gas and natural gas liquids production would result in an approximate $10.5 million decline in our revenues for 2015.

We periodically seek to reduce our exposure to commodity price volatility by hedging a portion of production through commodity derivative instruments. In the settlement of a typical hedge transaction, we will have the right to receive from the counterparties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparties this difference multiplied by the quantity hedged. During the year ended December 31, 2014, we paid approximately $3.0 million to the counterparties to our derivative instruments in connection with net hedge settlements.

We are required to pay the difference between the floating price and the fixed price (when the floating price exceeds the fixed price) regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge.

Our Credit Agreement requires that the counterparties to our hedge contracts be lenders under the Credit Agreement or, if not a lender under the Credit Agreement, rated A/A2 or higher by S&P or Moody's. Currently, the counterparties to our existing hedge contracts are JPMorgan Chase Bank, Wells Fargo Bank, Bank of America, The Bank of Nova Scotia and Capital One, N.A., all of whom are lenders under the Credit Agreement. To the extent we enter into additional hedge contracts, we would expect that certain of the lenders under the Credit Agreement would serve as counterparties.

As of December 31, 2014, we had entered into the following gas hedge contracts:

Production Period	**Instrument Type**	**Daily Volumes**	**Weighted Average Price**
Natural Gas:			
2015	Swap	30,000 Mmbtu	$3.82

During January and February 2015, we entered into the following additional hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
February - December 2015	Swap	10,000 Mmbtu	$2.93
July 2015 - June 2016	Swap	10,000 Mmbtu	$3.22
March 2015 - December 2015	Swap	15,000 Mmbtu	$2.99
Crude Oil:			
February - December 2015	Swap (LLS)	250 Bbls	$54.00
March 2015 - December 2015	Swap (LLS)	250 Bbls	$59.35
Propane:			
March 2015 - December 2015	Swap	250 Bbls	$25.62

LLS - Louisiana Light Sweet

After executing the above transactions, the Company has approximately 20.7 Bcf of gas volumes, at an average price of $3.44 per Mcf, approximately 160,000 barrels of oil volumes at an average price of $56.56 per barrel, and 76,500 barrels of propane volumes at an average price of $25.62 hedged for 2015.

Debt outstanding under our bank credit facility is subject to a floating interest rate and represents 18% of our total debt as of December 31, 2014. Based upon an analysis, utilizing the actual interest rate in effect and balances outstanding as of December 31, 2014, and assuming a 10% increase in interest rates and no changes in the amount of debt outstanding, the potential effect on interest expense for 2015 would be immaterial.

Item 8. Financial Statements and Supplementary Data

Information concerning this Item begins on page F-1.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the Company's management, including its Chief Executive Officer and Chief Financial Officer, carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the following:

i. that the Company's disclosure controls and procedures are designed to ensure (a) that information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and (b) that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure; and

ii. that the Company's disclosure controls and procedures are effective.

Notwithstanding the foregoing, there can be no assurance that the Company's disclosure controls and procedures will detect or uncover all failures of persons within the Company and its consolidated subsidiaries to disclose material information otherwise required to be set forth in the Company's periodic reports. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2014 that have materially affected, or that are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, and for performing an assessment of the effectiveness of internal control over financial reporting as of December 31, 2014. 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. Our system of 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 the assets of the Company; (ii) 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 (iii) 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. Projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management performed an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014 based upon criteria in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our assessment, management believes that our internal control over financial reporting was effective as of December 31, 2014 based on these criteria.

Ernst & Young LLP, our independent registered public accounting firm, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2014.

March 6, 2015

/s/ Charles T. Goodson
Charles T. Goodson
Chairman and
Chief Executive Officer

/s/ J. Bond Clement
J. Bond Clement
Executive Vice President-
Chief Financial Officer

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
PetroQuest Energy, Inc.

We have audited PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). PetroQuest Energy, Inc.'s 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, PetroQuest Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the three years in the period ended December 31, 2014 and our report dated March 6, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 6, 2015

Item 9B. **Other Information**

NONE

PART III

Items 10, 11, 12, 13, & 14.

Pursuant to General Instruction G of Form 10-K, the information concerning Item 10. Directors, Executive Officers and Corporate Governance, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13. Certain Relationships and Related Transactions, and Director Independence and Item 14. Principal Accounting Fees and Services, is incorporated by reference to the information set forth in the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held May 20, 2015, to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 with the Securities and Exchange Commission.

PART IV

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

(a) 1. FINANCIAL STATEMENTS

The following financial statements of the Company and the Report of the Company's Independent Registered Public Accounting Firm thereon are included on pages F-1 through F-27 of this Form 10-K:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2014 and 2013
Consolidated Statements of Operations for the three years ended December 31, 2014
Consolidated Statements of Comprehensive Income (Loss) for the three years ended December 31, 2014
Consolidated Statements of Cash Flows for the three years ended December 31, 2014
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2014
Notes to Consolidated Financial Statements

2. FINANCIAL STATEMENT SCHEDULES:

All schedules are omitted because the required information is inapplicable or the information is presented in the Financial Statements or the notes thereto.

3. EXHIBITS:

** 2.1	Plan and Agreement of Merger by and among Optima Petroleum Corporation, Optima Energy (U.S.) Corporation, its wholly-owned subsidiary, and Goodson Exploration Company, NAB Financial L.L.C., Dexco Energy, Inc., American Explorer, L.L.C. (incorporated herein by reference to Appendix G of the Proxy Statement on Schedule 14A filed July 22, 1998).
** 2.2	Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration II, L.P. (incorporated herein by reference to Exhibit 2.1 to Form 8-K filed on June 20, 2013).
** 2.3	Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration III, L.P. (incorporated herein by reference to Exhibit 2.2 to Form 8-K filed on June 20, 2013).
** 2.4	Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration IV, L.P. (incorporated herein by reference to Exhibit 2.3 to Form 8-K filed on June 20, 2013).
** 2.5	Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and GOM-H Exploration, LLC (incorporated herein by reference to Exhibit 2.4 to Form 8-K filed on June 20, 2013).
3.1	Certificate of Incorporation of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed September 16, 1998).
3.2	Certificate of Amendment to Certificate of Incorporation dated May 14, 2008 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed June 23, 2009).
3.3	Bylaws of PetroQuest Energy, Inc., as amended of December 20, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed December 21, 2007).
3.4	Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K filed September 16, 1998).
3.5	Certificate of Designations, Preferences, Limitations and Relative Rights of The Series a Junior Participating Preferred Stock of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit A of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).
3.6	Certificate of Designations establishing the 6.875% Series B Cumulative Convertible Perpetual Preferred Stock, dated September 24, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed on September 24, 2007).
4.1	Rights Agreement dated as of November 7, 2001 between PetroQuest Energy, Inc. and American Stock Transfer & Trust Company, as Rights Agent, including exhibits thereto (incorporated herein by reference to Exhibit 1 to Form 8-A filed November 9, 2001).
4.2	Form of Rights Certificate (incorporated herein by reference to Exhibit C of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).
4.3	Indenture, dated August 19, 2010, between PetroQuest Energy, Inc. and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on August 19, 2010).
4.5	First Supplemental Indenture, dated August 19, 2010, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed on August 19, 2010).
4.6	Second Supplemental Indenture, dated July 3, 2013, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on July 3, 2013).

*4.7	Third Supplemental Indenture, dated October 23, 2013, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and The Bank of New York Mellon Trust Company, N.A.
4.8	Registration Rights Agreement, dated July 3, 2013, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and J.P. Morgan Securities LLC, as representative of the several initial purchasers named therein (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed on July 3, 2013).
†10.1	PetroQuest Energy, Inc. 1998 Incentive Plan, as amended and restated effective May 14, 2008 (the "Incentive Plan") (incorporated herein by reference to Appendix A of the Proxy Statement on Schedule 14A filed April 9, 2008).
†10.2	Form of Incentive Stock Option Agreement for executive officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 10-K filed February 27, 2009).
†10.3	Form of Nonstatutory Stock Option Agreement under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Form 10-K filed February 27, 2009).
†10.4	Form of Restricted Stock Agreement for executive officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.4 to Form 10-K filed February 27, 2009).
†10.5	PetroQuest Energy, Inc. Annual Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on May 13, 2010).
†10.6	PetroQuest Energy, Inc. Annual Incentive Plan, as amended and restated (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on June 8, 2010).
†10.7	PetroQuest Energy, Inc. 2012 Employee Stock Purchase Plan (incorporated herein by reference to Appendix A to Schedule 14A filed March 28, 2012).
†10.8	PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 15, 2012).
†10.9	PetroQuest Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on April 9, 2013).
†10.10	Form of Award Notice of Restricted Stock Units - Employees (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed November 15, 2012).
†10.11	Form of Award Notice of Restricted Stock Units - Outside Director/Consultant under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed November 15, 2012).
†10.12	Form of Restricted Stock Agreement - Executive Officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.4 to Form 8-K filed November 15, 2012).
†10.13	Form of Restricted Stock Units Agreement - Employees (including Charles T. Goodson, W.Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 19, 2014).

†10.14	Form of Award Notice of Phantom Stock Units - Employees (including Charles T. Goodson, W.Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed November 19, 2014).
†10.15	Form of Performance Unit Notice and Award- Employees (including Charles T. Goodson, W.Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 21, 2014).
10.16	Credit Agreement dated as of October 2, 2008, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A., and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed October 6, 2008).
10.17	First Amendment to Credit Agreement dated as of March 24, 2009, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed March 24, 2009).
10.18	Second Amendment to Credit Agreement dated as of September 30, 2009, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed October 1, 2009).
10.19	Third Amendment to Credit Agreement dated as of August 5, 2010, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Credit Agricole Corporate and Investment Bank, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on August 6, 2010).
10.20	Fourth Amendment to Credit Agreement dated as of October 3, 2011, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed on October 4, 2011).
10.21	Fifth Amendment to Credit Agreement dated as of March 29, 2013, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IBERIABANK and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed on March 29, 2013).
10.22	Sixth Amendment to Credit Agreement dated as of June 19, 2013, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IBERIABANK and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on June 20, 2013).
10.23	Seventh Amendment to Credit Agreement dated as of March 31, 2014, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on March 31, 2014).
10.24	Eighth Amendment to Credit Agreement dated as of September 29, 2014, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on September 30, 2014).
10.25	Ninth Amendment to Credit Agreement dated as of February 26, 2015, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on February 26, 2015).

†10.26	Amended Executive Employment Agreement dated effective as of December 31, 2008, between Charles T. Goodson and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed January 6, 2009).
†10.27	Amended Executive Employment Agreement dated effective as of December 31, 2008, between W. Todd Zehnder and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed January 6, 2009).
†10.28	Amended Executive Employment Agreement dated effective as of December 31, 2008, between Arthur M. Mixon, III and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed January 6, 2009).
†10.29	Amended Executive Employment Agreement dated effective as of December 31, 2008, between J. Bond Clement and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed February 27, 2009).
†10.30	Executive Employment Agreement dated May 8, 2012 between PetroQuest Energy, Inc. and Tracy Price (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed May 10, 2012).
†10.31	Executive Employment Agreement dated February 1, 2014 between PetroQuest Energy, Inc. and Edward E. Abels, Jr. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed February 5, 2014).
†10.32	Form of Amended Termination Agreement between the Company and each of its executive officers, including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, and J. Bond Clement (incorporated herein by reference to Exhibit 10.6 to Form 8-K filed January 6, 2009).
†10.33	Termination Agreement dated May 8, 2012 between PetroQuest Energy, Inc. and Tracy Price (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed May 10, 2012).
†10.34	Termination Agreement dated February 1, 2014 between PetroQuest Energy, Inc. and Edward E. Abels, Jr. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed February 5, 2014).
†10.35	Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, , J. Bond Clement, Tracy Price, Edward E. Abels, Jr., William W. Rucks, IV, E. Wayne Nordberg, Michael L. Finch, W.J. Gordon, III and Charles F. Mitchell, II (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).
†10.36	Form of Surrender and Cancellation Agreement for Directors and Executive Officers (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on September 16, 2010).
10.37	Joint Development Agreement dated May 17, 2010, among PetroQuest Energy, L.L.C., a Louisiana limited liability company, WSGP Gas Producing, LLC, a Delaware limited liability company, and NextEra Energy Gas Producing, LLC, a Delaware limited liability company (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed on August 5, 2010).
*10.38	First Amendment to the Joint Development Agreement dated May 17, 2010, among PetroQuest Energy, L.L.C., a Louisiana limited liability company, WSGP Gas Producing, LLC, a Delaware limited liability company, and NextEra Energy Gas Producing, LLC, a Delaware limited liability company.
10.39	Second Amendment to the Joint Development Agreement dated February 24, 2012, among PetroQuest Energy, L.L.C., a Louisiana limited liability company, WSGP Gas Producing, LLC, a Delaware limited liability company, and NextEra Energy Gas Producing, LLC, a Delaware limited liability company (incorporated herein by reference to Exhibit 10.22 to Form 10-K filed March 5, 2012).

14.1	Code of Business Conduct and Ethics (incorporated herein by reference to Exhibit 14.1 to Form 10-K filed March 8, 2006).
*21.1	Subsidiaries of the Company.
*23.1	Consent of Independent Registered Public Accounting Firm.
*23.2	Consent of Ryder Scott Company, L.P.
*31.1	Certification of Chief Executive Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
*31.2	Certification of Chief Financial Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
*32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Executive Officer.
*32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Financial Officer.
*99.1	Reserve report letter as of December 31, 2014, as prepared by Ryder Scott Company, L.P.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definitions Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** The registrant agrees to furnish supplementally a copy of any omitted schedule to the Agreements to the SEC upon request.

† Management contract or compensatory plan or arrangement

(b) Exhibits. See Item 15 (a) (3) above.
(c) Financial Statement Schedules. None

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas used in this Form 10-K.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

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

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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 gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

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

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

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.

Lead. A specific geographic area which, based on supporting geological, geophysical or other data, is deemed to have potential for the discovery of commercial hydrocarbons.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

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

Ngl. Natural gas liquid.

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

Possible reserves. Those additional reserves that are less certain to be recovered than probable reserves.

Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved area. The part of a property to which proved reserves have been specifically attributed.

Proved oil and gas reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved properties. Properties with proved reserves.

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

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 and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

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

Resources. Quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production.

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Unproved properties. Properties with no proved reserves

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 6, 2015.

PETROQUEST ENERGY, INC.

By: /s/ Charles T. Goodson

CHARLES T. GOODSON
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 6, 2015.

By:	/s/ Charles T. Goodson	Chairman of the Board, President, Chief Executive Officer and Director
	CHARLES T. GOODSON	(Principal Executive Officer)
By:	/s/ J. Bond Clement	Executive Vice President, Chief Financial Officer, Treasurer
	J. BOND CLEMENT	(Principal Financial and Accounting Officer)
By:	/s/ W.J. Gordon, III	Director
	W.J. GORDON, III	
By:	/s/ Michael L. Finch	Director
	MICHAEL L. FINCH	
By:	/s/ Charles F. Mitchell, II, M.D.	Director
	CHARLES F. MITCHELL, II, M.D.	
By:	/s/ E. Wayne Nordberg	Director
	E. WAYNE NORDBERG	
By:	/s/ William W. Rucks, IV	Director
	WILLIAM W. RUCKS, IV	

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
PetroQuest Energy, Inc.

We have audited the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), cash flows and stockholders' equity for each of the three years in the period ended December 31, 2014. 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 PetroQuest Energy, Inc. at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 6, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 6, 2015

PETROQUEST ENERGY, INC.
Consolidated Balance Sheets
(Amounts in Thousands)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,243	$ 9,153
Revenue receivable	16,485	26,568
Joint interest billing receivable	46,778	26,556
Derivative asset	8,631	521
Prepaid drilling costs	847	477
Other current assets	5,566	8,132
Total current assets	96,550	71,407
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	2,222,753	2,035,899
Unevaluated oil and gas properties	109,119	98,387
Accumulated depreciation, depletion and amortization	(1,648,060)	(1,553,044)
Oil and gas properties, net	683,812	581,242
Other property and equipment	14,953	13,993
Accumulated depreciation of other property and equipment	(10,313)	(8,901)
Total property and equipment	688,452	586,334
Other assets, net of accumulated amortization of $7,847 and $5,689, respectively	5,893	9,449
Total assets	$ 790,895	$ 667,190
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 102,954	$ 47,341
Advances from co-owners	12,819	969
Oil and gas revenue payable	22,333	22,664
Accrued interest and preferred stock dividend	12,764	12,909
Asset retirement obligation	2,756	3,113
Derivative liability	—	1,617
Accrued acquisition costs	17,690	—
Other accrued liabilities	5,394	8,924
Total current liabilities	176,710	97,537
Bank debt	75,000	75,000
10% Senior Notes	350,000	350,000
Asset retirement obligation	52,214	45,423
Other long-term liability	62	135
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $.001 par value; authorized 5,000 shares; issued and outstanding 1,495 shares	1	1
Common stock, $.001 par value; authorized 150,000 shares; issued and outstanding 64,721 and 63,664 shares, respectively	65	64
Paid-in capital	285,957	280,711
Accumulated other comprehensive income (loss)	5,420	(1,096)
Accumulated deficit	(154,534)	(180,585)
Total stockholders' equity	136,909	99,095
Total liabilities and stockholders' equity	$ 790,895	$ 667,190

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Operations
(Amounts in Thousands, Except Per Share Data)

	Year Ended December 31, 2014	2013	2012
Revenues:			
Oil and gas sales	$ 225,021	$ 182,804	$ 141,433
Expenses:			
Lease operating expenses	48,597	43,743	38,890
Production taxes	5,927	3,950	885
Depreciation, depletion and amortization	87,818	71,445	60,689
Ceiling test write-down	—	—	137,100
General and administrative	22,870	26,512	22,957
Accretion of asset retirement obligation	2,958	1,753	2,078
Interest expense	29,281	21,886	9,808
	197,451	169,289	272,407
Other income (expense):			
Other income	679	654	764
Derivative income (expense)	—	233	(233)
	679	887	531
Income (loss) from operations	28,249	14,402	(130,443)
Income tax expense (benefit)	(2,941)	320	1,636
Net income (loss)	31,190	14,082	(132,079)
Preferred stock dividend	5,139	5,139	5,139
Net income (loss) available to common stockholders	$ 26,051	$ 8,943	$ (137,218)
Earnings per common share:			
Basic			
Net income (loss) per share	$ 0.39	$ 0.14	$ (2.20)
Diluted			
Net income (loss) per share	$ 0.39	$ 0.14	$ (2.20)
Weighted average number of common shares:			
Basic	64,204	63,054	62,459
Diluted	64,225	63,208	62,459

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Comprehensive Income (Loss)
(Amounts in Thousands)

	Year Ended December 31, 2014	2013	2012
Net income (loss)	$ 31,190	$ 14,082	$ (132,079)
Change in fair value of derivatives, net of income tax (expense) benefit of ($3,211), $309 and $2,079 respectively	6,516	(1,617)	(3,510)
Comprehensive income (loss)	$ 37,706	$ 12,465	$ (135,589)

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Cash Flows
(Amounts in Thousands)

	Year Ended December 31, 2014	2013	2012
Cash flows from operating activities:			
Net income (loss)	$ 31,190	$ 14,082	$ (132,079)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred tax expense (benefit)	(2,941)	320	1,636
Depreciation, depletion and amortization	87,818	71,445	60,689
Ceiling test write-down	—	—	137,100
Accretion of asset retirement obligation	2,958	1,753	2,078
Share based compensation expense	5,248	4,216	6,910
Amortization costs and other	2,188	1,473	881
Non-cash derivative expense (income)	—	(233)	233
Payments to settle asset retirement obligations	(3,623)	(3,335)	(2,627)
Changes in working capital accounts:			
Revenue receivable	10,083	(8,826)	(1,882)
Prepaid drilling and pipe costs	(370)	1,221	4,479
Joint interest billing and other receivable	(20,276)	15,685	3,981
Accounts payable and accrued liabilities	50,243	(12,865)	20,916
Advances from co-owners	11,850	(19,490)	(13,408)
Other	3,840	(5,592)	(316)
Net cash provided by operating activities	178,208	59,854	88,591
Cash flows used in investing activities:			
Investment in oil and gas properties	(174,633)	(298,824)	(147,771)
Investment in other property and equipment	(926)	(1,679)	(1,743)
Sale of oil and gas properties	8,610	19,913	837
Sale of unevaluated oil and gas properties	3,298	487	8,889
Net cash used in investing activities	(163,651)	(280,103)	(139,788)
Cash flows used in financing activities:			
Net payments for share based compensation	(75)	(38)	(981)
Deferred financing costs	(253)	(320)	(42)
Payment of preferred stock dividend	(5,139)	(5,139)	(5,139)
Proceeds from bank borrowings	17,500	73,000	102,500
Repayment of bank borrowings	(17,500)	(48,000)	(52,500)
Proceeds from issuance of 10% Senior Notes	—	200,000	—
Costs to issue 10% Senior Notes	—	(5,005)	—
Net cash provided by (used in) financing activities	(5,467)	214,498	43,838
Net increase (decrease) in cash and cash equivalents	9,090	(5,751)	(7,359)
Cash and cash equivalents, beginning of period	9,153	14,904	22,263
Cash and cash equivalents, end of period	$ 18,243	$ 9,153	$ 14,904
Supplemental disclosure of cash flow information:			
Cash paid during the period for:			
Interest	$ 37,174	$ 20,101	$ 16,026
Income taxes	$ 270	$ 12	$ 105

See accompanying Notes to Consolidated Financial Statements.

PetroQuest Energy Inc.
Consolidated Statements of Stockholders' Equity
(*Amounts in Thousands*)

	Common Stock	Preferred Stock	Paid-In Capital	Other Comprehensive Income (Loss)	Accumulated Deficit	Total Stockholders' Equity
December 31, 2011	$ 62	$ 1	$ 270,606	$ 4,031	$ (52,310)	$ 222,390
Options exercised	—	—	260	—	—	260
Retirement of shares upon vesting of restricted stock	1	—	(1,242)	—	—	(1,241)
Share-based compensation expense	—	—	6,910	—	—	6,910
Derivative fair value adjustment, net of tax	—	—	—	(3,510)	—	(3,510)
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net loss	—	—	—	—	(132,079)	(132,079)
December 31, 2012	$ 63	$ 1	$ 276,534	$ 521	$ (189,528)	$ 87,591
Options exercised	—	—	731	—	—	731
Retirement of shares upon vesting of restricted stock	1	—	(1,057)	—	—	(1,056)
Share-based compensation expense	—	—	4,216	—	—	4,216
Issuance of shares under employee stock purchase plan	—	—	287	—	—	287
Derivative fair value adjustment, net of tax	—	—	—	(1,617)	—	(1,617)
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net income	—	—	—	—	14,082	14,082
December 31, 2013	$ 64	$ 1	$ 280,711	$ (1,096)	$ (180,585)	$ 99,095
Options exercised	—	—	1,032	—	—	1,032
Retirement of shares upon vesting of restricted stock	1	—	(1,310)	—	—	(1,309)
Share-based compensation expense	—	—	5,248	—	—	5,248
Issuance of shares under employee stock purchase plan	—	—	276	—	—	276
Derivative fair value adjustment, net of tax	—	—	—	6,516	—	6,516
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net income	—	—	—	—	31,190	31,190
December 31, 2014	$ 65	$ 1	$ 285,957	$ 5,420	$ (154,534)	$ 136,909

See accompanying Notes to Consolidated Financial Statements.

Note 1—Organization and Summary of Significant Accounting Policies

PetroQuest Energy, Inc. (a Delaware Corporation) ("PetroQuest") is an independent oil and gas company headquartered in Lafayette, Louisiana with exploration offices in The Woodlands, Texas and Tulsa, Oklahoma. It is engaged in the exploration, development, acquisition and operation of oil and gas properties in Oklahoma and Texas as well as onshore and in the shallow waters offshore the Gulf Coast Basin.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of PetroQuest and its subsidiaries, PetroQuest Energy, L.L.C., PetroQuest Oil & Gas, L.L.C, Pittrans, Inc. and TDC Energy LLC (collectively, the "Company"). All intercompany accounts and transactions have been eliminated. Certain prior period amounts have been reclassified to conform to current year presentation.

Use of Estimates

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

Oil and Gas Properties

The Company utilizes the full cost method of accounting, which involves capitalizing all acquisition, exploration and development costs incurred for the purpose of finding oil and gas reserves including the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. The Company also capitalizes the portion of general and administrative costs that can be directly identified with acquisition, exploration or development of oil and gas properties. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties, the properties are sold, or management determines these costs to have been impaired. Interest is capitalized on unevaluated property costs. Transactions involving sales of reserves in place are recorded as adjustments to accumulated depreciation, depletion and amortization with no gain or loss recognized, unless such adjustments would cause a significant alteration in the relationship between capitalized costs and proved reserves.

Depreciation, depletion and amortization of oil and gas properties is computed using the unit-of-production method based on estimated proved reserves. All costs associated with evaluated oil and gas properties, including an estimate of future development costs associated therewith, are included in the depreciable base. The costs of investments in unevaluated properties are excluded from this calculation until the related properties are evaluated, proved reserves are established or the properties are determined to be impaired. Proved oil and gas reserves are estimated annually by independent petroleum engineers.

The capitalized costs of proved oil and gas properties cannot exceed the present value of the estimated net future cash flows from proved reserves based on historical first of the month average twelve-month oil, gas and natural gas liquid prices, including the effect of hedges in place (the full cost ceiling). If the capitalized costs of proved oil and gas properties exceed the full cost ceiling, the Company is required to write-down the value of its oil and gas properties to the full cost ceiling amount. The Company follows the provisions of Staff Accounting Bulletin ("SAB") No. 106, regarding the application of ASC Topic 410-20 by companies following the full cost accounting method. SAB No. 106 indicates that estimated future dismantlement and abandonment costs that are recorded on the balance sheet are to be included in the costs subject to the full cost ceiling limitation. The estimated future cash outflows associated with settling the recorded asset retirement obligations should be excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test.

Cash and Cash Equivalents

The Company considers all highly liquid investments with a stated maturity of three months or less to be cash and cash equivalents. The majority of the Company's cash and cash equivalents are in overnight securities made through its commercial bank accounts, which result in available funds the next business day.

Accounts Receivable

In its capacity as operator, the Company incurs drilling and operating costs that are billed to its partners based on their respective working interests. As of December 31, 2014 and 2013, the Company had $0.1 million recorded related to an allowance for doubtful accounts on its joint interest billing receivable.

Other Current Assets

Other current assets at December 31, 2014 and 2013 included $0.9 million and $3.1 million, respectively, related to an insurance receivable with respect to an operational related claim in our Oklahoma acreage.

Other Property and Equipment

During 2006, the Company acquired a gas gathering system used in the transportation of natural gas. The costs related to this system are depreciated on a straight line basis over the estimated remaining useful life, generally 14 years. The costs related to other furniture and fixtures are depreciated on a straight line basis over estimated useful lives ranging from 3-8 years. During 2012, a field office servicing the Company's Oklahoma assets was built and is being depreciated over 39 years.

Other Assets

Other assets at December 31, 2014 and 2013 included $5.5 million and $7.4 million, respectively, related to deferred financing costs, which are amortized over the life of the related debt.

Income Taxes

The Company accounts for income taxes in accordance with ASC Topic 740. Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures are capitalized and depreciated, depleted and amortized on the unit-of-production method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, the Company may use certain provisions of the Internal Revenue Code which allow capitalization of intangible drilling costs. Other financial and income tax reporting differences occur primarily as a result of statutory depletion. Deferred tax assets are assessed for realizabilty and a valuation allowance is established for any portion of the asset for which it is more likely than not will not be realized.

Revenue Recognition

The Company records natural gas and oil revenue under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of natural gas or oil sold to purchasers, which may differ from the amounts to which the Company is entitled based on its interest in the properties. Gas imbalances as of December 31, 2014 and 2013 were not significant.

Certain Concentrations

The Company’s production is sold on month to month contracts at prevailing prices. The Company attempts to diversify its sales among multiple purchasers and obtain credit protection such as letters of credit and parental guarantees when necessary.

The following table identifies customers from whom the Company derived 10% or more of its oil and gas revenues during the years presented. Based on the availability of other customers, the Company does not believe the loss of any of these customers would have a significant effect on its business or financial condition.

	Year Ended December 31,		
	2014	2013	2012
Shell Trading Co.	30%	35%	30%
Laclede Energy	24%	14%	17%
Unimark, LLC	14%	14%	(a)
JP Morgan Ventures Energy	(a)	(a)	12%

(a) Less than 10 percent

Derivative Instruments

Under ASC Topic 815, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in stockholders' equity through other comprehensive income (loss), net of related taxes, to the extent the hedge is effective. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income (expense). The Company does not offset fair value amounts recognized for derivative instruments. The cash settlements of hedges are recorded as adjustments to oil and gas sales. Oil and gas revenues include additions (reductions) related to the net settlement of hedges totaling ($3.0) million, $0.9 million and $9.1 million during 2014, 2013 and 2012, respectively.

The Company's hedges are specifically referenced to NYMEX prices for oil and natural gas and OPIS Mt. Bellevue pricing for natural gas liquids. The effectiveness of hedges is evaluated at the time the contracts are entered into, as well as periodically over the life of the contracts, by analyzing the correlation between NYMEX and OPIS Mt. Bellevue prices and the posted prices received from the designated production. Through this analysis, the Company is able to determine if a high correlation exists between the prices received for its designated production and the NYMEX and OPIS Mt. Bellevue prices at which the hedges will be settled. At December 31, 2014, the Company's derivative instruments were designated as effective cash flow hedges. See Note 7 for further discussion of the Company's derivative instruments.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, "Revenue from Contracts with Customers" to clarify the principles for recognizing revenue and to develop a common revenue standard and disclosure requirements. The core principle of ASU 2014-09 is that an entity will recognize revenue when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods and or services. The standard is effective for fiscal years beginning after December 15, 2016, and for interim periods within those fiscal years. Early application is not permitted. Entities can choose to apply the standard using either a full retrospective approach or a modified retrospective approach, with the cumulative effect of initially applying ASU 2014-09 recognized at the date of initial application. We are currently evaluating the effect that this new standard will have on our consolidated financial statements and related disclosures, however, we do not expect the adoption of the standard will have a material impact on our results of operations, financial position, or related disclosures.

Note 2—Acquisitions

Gulf of Mexico Acquisition:

On July 3, 2013, the Company acquired certain shallow water Gulf of Mexico shelf oil and gas properties (the "Acquired Assets"), for an aggregate cash purchase price of $188.8 million, reflecting an effective date of January 1, 2013 (collectively, the "Gulf of Mexico Acquisition"). The Acquired Assets included 16 gross wells located on seven platforms.

The aggregate cash purchase price of the Gulf of Mexico Acquisition was financed with the net proceeds from the sale of $200 million in aggregate principal amount of the Company's 10% Senior Notes due 2017. The Company subsequently registered the 10% Senior Notes due 2017 in an exchange offer completed in September 2013 (the "New Notes"). The New Notes are substantially identical to the Company's existing $150 million aggregate principal amount of 10% Senior Notes due 2017. In connection with the transaction, the Company recorded $5 million of deferred financing costs related to the New Notes and incurred $4.0 million of acquisition-related costs, including $2.6 million related to a bridge commitment fee, which were recognized as general and administrative expenses during 2013.

The Gulf of Mexico Acquisition was accounted for under the acquisition method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed. The fair value of proved and unevaluated oil and gas properties was estimated using the income approach based on estimated reserve quantities, costs to produce and develop reserves, and forward prices for oil and gas, which represent Level 2 and Level 3 inputs. Asset retirement obligations were determined in accordance with applicable accounting standards.

The following table summarizes the acquisition date fair values of the net assets acquired (in thousands):

Oil and gas properties	$	192,067
Unevaluated oil and gas properties		12,033
Asset retirement obligations		(15,319)
Net assets acquired	$	188,781

The following unaudited summary pro forma financial information for the twelve month periods ended December 31, 2013 and 2012 has been prepared to give effect to the Gulf of Mexico Acquisition as if it had occurred on January 1, 2012. The pro forma financial information is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2012 and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following unaudited pro forma financial information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities and other factors. Amounts are presented in thousands, except per share amounts.

	Twelve Months Ended December 31,			
	2013		2012	
Revenues	$	215,666	$	187,104
Income (Loss) from Operations		19,858		(135,406)
Net Income (Loss) available to common stockholders		14,399		(142,181)
Basic Earnings (loss) per Share	$	0.22	$	(2.28)
Diluted Earnings (loss) per Share	$	0.22	$	(2.28)

Fleetwood Joint Venture:

In June 2014, we entered into a joint venture in Louisiana for an aggregate purchase price of $24 million. The assets acquired under the joint venture include an average 37% working interest in an approximately 30,000 acre leasehold position in Louisiana and exclusive rights, along with our joint venture partner, to a 200 square mile proprietary 3D survey which has generated several conventional and shallow non-conventional oil focused prospects.

The purchase price was comprised of $10 million in cash and $14 million in cash funding for future drilling, completion and lease acquisition costs. If the $14 million in drilling, completion and lease acquisition costs is not fully funded by December 31, 2015, any remaining balance becomes payable at the election of our joint venture partner. At December 31, 2014, $7.0 million of the cash purchase price and $10.7 million of the cash funding for future drilling, completion and lease acquisition costs remained outstanding. The total liability of $17.7 million at December 31, 2014 is reflected as accrued acquisition costs in the Consolidated Balance Sheet.

Note 3—Convertible Preferred Stock

The Company has 1,495,000 shares of 6.875% Series B Cumulative Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") outstanding.

The following is a summary of certain terms of the Series B Preferred Stock:

Dividends. The Series B Preferred Stock accumulates dividends at an annual rate of 6.875% for each share of Series B Preferred Stock. Dividends are cumulative from the date of first issuance and, to the extent payment of dividends is not prohibited by the Company's debt agreements, assets are legally available to pay dividends and the Company's board of directors or an authorized committee of the board declares a dividend payable, the Company pays dividends in cash, every quarter.

Mandatory conversion. The Company may, at its option, cause shares of the Series B Preferred Stock to be automatically converted at the applicable conversion rate, but only if the closing sale price of the Company's common stock for 20 trading days within a period of 30 consecutive trading days ending on the trading day immediately preceding the date the Company gives the conversion notice equals or exceeds 130% of the conversion price in effect on each such trading day.

Conversion rights. Each share of Series B Preferred Stock may be converted at any time, at the option of the holder, into 3.4433 shares of the Company's common stock (which is based on an initial conversion price of approximately $14.52 per share of common stock, subject to adjustment) plus cash in lieu of fractional shares, subject to the Company's right to settle all or a portion of any such conversion in cash or shares of the Company's common stock. If the Company elects to settle all or any portion of its conversion obligation in cash, the conversion value and the number of shares of the Company's common stock it will deliver upon conversion (if any) will be based upon a 20 trading day averaging period.

Upon any conversion, the holder will not receive any cash payment representing accumulated and unpaid dividends on the Series B Preferred Stock, whether or not in arrears, except in limited circumstances. The conversion rate is equal to $50 divided by the conversion price at the time. The conversion price is subject to adjustment upon the occurrence of certain events. The conversion price on the conversion date and the number of shares of the Company's common stock, as applicable, to be delivered upon conversion may be adjusted if certain events occur.

Note 4—Earnings Per Share

A reconciliation between the basic and diluted earnings per share computations (in thousands, except per share amounts) is as follows:

For the Year Ended December 31, 2014	Income (Numerator)	Shares (Denominator)	Per Share Amount
Net income available to common stockholders	$ 26,051	64,204	
Attributable to participating securities	(855)	—	
BASIC EPS	$ 25,196	64,204	$ 0.39
Net income available to common stockholders	$ 26,051	64,204	
Effect of dilutive securities:			
Stock options	—	21	
Attributable to participating securities	(854)	—	
DILUTED EPS	$ 25,197	64,225	$ 0.39
For the Year Ended December 31, 2013	Income (Numerator)	Shares (Denominator)	Per Share Amount
Net income available to common stockholders	$ 8,943	63,054	
Attributable to participating securities	(257)	—	
BASIC EPS	$ 8,686	63,054	$ 0.14
Net income available to common stockholders	$ 8,943	63,054	
Effect of dilutive securities:			
Stock options	—	154	
Attributable to participating securities	(256)	—	
DILUTED EPS	$ 8,687	63,208	$ 0.14
For the Year Ended December 31, 2012	Loss (Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
Net loss available to common stockholders	$ (137,218)	62,459	$ (2.20)
Effect of dilutive securities:			
Stock options	—	—	
Restricted stock	—	—	
DILUTED EPS	$ (137,218)	62,459	$ (2.20)

Common shares issuable upon the assumed conversion of the Series B Preferred Stock totaling 5.1 million shares during 2014 and 2013 were not included in the computation of diluted earnings per share because the inclusion would have been anti-dilutive. Options to purchase 1.0 million and 1.2 million shares of common stock were outstanding during the year ended December 31, 2014 and 2013, respectively, and were not included in the computation of diluted earnings per share because the options' exercise prices were in excess of the average market price of the common shares.

An aggregate of 0.9 million shares of common stock representing options to purchase common stock and unvested shares of restricted common stock and common shares issuable upon the assumed conversion of the Series B Preferred Stock totaling 5.1 million shares were not included in the computation of diluted earnings per share for the year ended December 31, 2012, because the inclusion would have been anti-dilutive as a result of the net loss reported for the year.

Note 5—Share-Based Compensation

The Company accounts for share-based compensation in accordance with ASC Topic 718. Share-based compensation cost is recognized over the requisite service period. Compensation cost for awards with graded vesting is recognized using the accelerated attribution method. Share-based compensation cost is reflected as a component of general and administrative expenses. A detail of share-based compensation cost for the years ended December 31, 2014, 2013 and 2012 is as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Stock options:			
Incentive Stock Options	$ 573	$ 310	$ 786
Non-Qualified Stock Options	171	222	660
Restricted stock	4,504	3,684	5,464
Restricted stock units	3,094	1,611	277
Share-based compensation	$ 8,342	$ 5,827	$ 7,187

During the years ended December 31, 2014, 2013 and 2012 the Company capitalized $1.5 million, $0.8 million and $0.1 million of the above share-based compensation cost to oil and gas properties. During the years ended December 31, 2014, 2013 and 2012, the Company recorded income tax benefits of approximately $2.3 million, $1.8 million and $2.3 million, respectively, related to share-based compensation expense recognized during those periods. Any excess tax benefits from the vesting of restricted stock and the exercise of stock options will not be recognized in paid-in capital until the Company is in a current tax paying position. Presently, all of the Company's income taxes are deferred and the Company has net operating losses available to carryover to future periods. Accordingly, no excess tax benefits have been recognized for any periods presented.

At December 31, 2014, the Company had $7.6 million of unrecognized compensation cost related to unvested restricted stock and stock options. This amount will be recognized as compensation expense over a weighted average period of approximately three years.

Stock Options

Stock options generally vest equally over a three-year period, must be exercised within 10 years of the grant date and may be granted only to employees, directors and consultants. The exercise price of each option may not be less than 100% of the fair market value of a share of common stock on the date of grant. Upon a change in control of the Company, all outstanding options become immediately exercisable.

The Company computes the fair value of its stock options using the Black-Scholes option-pricing model assuming a stock option forfeiture rate and expected term based on historical activity and expected volatility computed using historical stock price fluctuations on a weekly basis for a period of time equal to the expected term of the option. Periodically, the Company adjusts compensation expense based on the difference between actual and estimated forfeitures.

The following table outlines the assumptions used in computing the fair value of stock options granted during 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
Dividend yield	—%	—%	—%
Expected volatility	79.4% - 80.0%	79.6% - 79.8%	79.2% - 79.6%
Risk-free rate	1.81% - 2.015%	0.9% - 1.815%	0.8% - 1.1%
Expected term	6 years	6 years	6 years
Forfeiture rate	5.0%	5.0%	5.0%
Stock options granted (1)	69,434	395,642	125,487
Wgtd. avg. grant date fair value per share	$2.84	$2.91	$3.71
Fair value of grants (1)	$197,000	$1,150,000	$465,000

(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2014:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	1,892,493	$ 5.67		
Granted	69,434	4.13		
Expired/cancelled/forfeited	(156,724)	5.60		
Exercised	(287,499)	3.34		
Outstanding at end of year	1,517,704	6.05	6.0 years	$ —
Options exercisable at end of year	1,172,400	$ 6.58	5.3 years	$ —
Options expected to vest	328,039	4.27	8.6 years	$ —

The total fair value of stock options that vested during the years ended December 31, 2014, 2013 and 2012 was $1.0 million, $0.8 million and $1.7 million, respectively. The intrinsic value of stock options exercised was immaterial for all periods presented.

The following table summarizes information regarding stock options outstanding at December 31, 2014:

Range of Exercise Price	Options Outstanding 12/31/2014	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/2014	Wgtd. Avg. Exercise Price
$2.24—$4.48	407,255	8.9 years	$4.14	115,945	$4.18
$4.48—$6.72	355,820	4.0 years	$5.63	301,826	$5.73
$6.72—$8.96	744,629	5.5 years	$7.25	744,629	$7.25
$8.96—$11.20	10,000	1.1 years	$9.99	10,000	$9.99
	1,517,704	6.0 years	$6.05	1,172,400	$6.58

Restricted Stock

The Company computes the fair value of its service based restricted stock using the closing price of the Company's stock at the date of grant, and compensation expense is recognized assuming a 5% estimated forfeiture rate. Restricted stock granted to employees prior to 2011 generally vests over a five-year period with one-fourth vesting on each of the first, second, third and fifth anniversaries of the date of the grant. No portion of the restricted stock vests on the fourth anniversary of the date of the grant. Prior to 2013, restricted stock granted to directors generally vested evenly over a three year period. In 2013, restricted stock granted to directors vests one year from the date of grant, to align with their term on the board. Beginning January 1, 2011, restricted stock granted to employees generally vests evenly over a three year period. Upon a change in control of the Company, all outstanding shares of restricted stock will become immediately vested.

The following table details restricted stock activity during the year ended December 31, 2014:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	1,926,451	$ 4.88
Granted	1,599,750	4.32
Expired/cancelled/forfeited	(135,861)	5.01
Lapse of restrictions	(962,138)	5.22
Outstanding at December 31, 2014	2,428,202	$ 4.37

The weighted average grant date fair value of restricted stock granted during the years ended December 31, 2014, 2013 and 2012 was $4.32, $4.18 and $5.24, respectively, per share. The total fair value of restricted stock that vested during the years ended December 31, 2014, 2013 and 2012 was $5.0 million, $5.4 million and $4.7 million, respectively. At December 31, 2014, the weighted average remaining life of restricted stock outstanding was approximately two years and the intrinsic value of restricted stock outstanding, using the closing stock price on December 31, 2014, was $9.4 million.

Restricted Stock Units

The Company grants restricted stock units ("RSUs") to employees that vest evenly over a three year period. Cash payment will be made to employees on each vesting date based upon the Company's closing stock price on that date. Upon change in control of the Company, all of the RSUs will immediately vest. The Company computes the fair value of the RSUs using the closing price of the Company's stock at the end of each period and records a liability based on the percentage of requisite service rendered at the reporting date. During 2014, the Company paid $2.0 million for units that vested during the period. As of December 31, 2014, the Company had a liability for RSUs outstanding and expected to vest in the amount of $1.4 million.

The following table details RSU activity during the year ended December 31, 2014:

	Number of Shares
Outstanding at beginning of year	1,273,417
Granted	669,469
Expired/Cancelled/Forfeited	(66,849)
Vested/Paid	(496,776)
Outstanding at December 31, 2014	1,379,261

Market Based Restricted Stock Units

The Company granted 243,067 market based restricted stock units ("MRSUs") to executive officers during November 2014. The executive officers could earn between 0-200% of the MRSUs granted based on the Company's performance versus a defined peer group. The MRSUs vest in one-third increments on each of the first, second and third annual anniversaries starting January 1, 2016. Upon change in control of the Company, all of the MRSUs will immediately vest. The number of MRSUs that ultimately vest is based on the Company's total shareholder return in the last 20 days of the fiscal year in relation to the last 20 days of the previous fiscal year in comparison to a group of 12 selected peer stocks of similar sized companies which operate within the same sector. The MRSUs are cash settled on each vesting date based on the number of MRSUs that vest multiplied by the Company's closing stock price. The Company estimates the fair value of the outstanding MRSUs using a Monte Carlo valuation model and records a liability based on the percentage of requisite service rendered at the reporting date. The Monte Carlo valuation model considers such inputs as the Company's and its peer group's stock prices, a risk-free interest rate, and an estimated volatility for the Company and its peer group. The liability for MSRUs was immaterial as of December 31, 2014.

Note 6—Asset Retirement Obligation

The Company accounts for asset retirement obligations in accordance with ASC Topic 410-20, which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. Asset retirement obligations associated with long-lived assets included within the scope of ASC Topic 410-20 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. The Company has legal obligations to plug, abandon and dismantle existing wells and facilities that it has acquired and constructed.

The following table describes the changes to the Company's asset retirement obligation (in thousands):

	Year Ended December 31, 2014	Year Ended December 31, 2013
Asset retirement obligation, beginning of period	$ 48,536	$ 27,260
Liabilities assumed	—	15,319
Liabilities incurred	756	498
Liabilities settled	(3,623)	(3,335)
Accretion expense	2,958	1,753
Revisions in estimated cash flows	6,343	7,041
Asset retirement obligation, end of period	54,970	48,536
Less: current portion of asset retirement obligation	(2,756)	(3,113)
Long-term asset retirement obligation	$ 52,214	$ 45,423

Note 7—Derivative Instruments

The Company seeks to reduce its exposure to commodity price volatility by hedging a portion of its production through commodity derivative instruments. When the conditions for hedge accounting are met, the Company may designate its commodity derivatives as cash flow hedges. The changes in fair value of derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil or natural gas quantities are produced. If a derivative does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the statement of operations as derivative income (expense). At December 31, 2014 and 2013, all of the Company's outstanding derivative instruments were designated as cash flow hedges. At December 31, 2012, all of the Company's outstanding derivative instruments were designated as cash flow hedges, except its three-way collar discussed below.

Oil and gas sales include additions (reductions) related to the settlement of gas hedges of ($4,237,000), $1,098,000 and $6,846,000, Ngl hedges of $296,000, $61,000 and $722,000, and oil hedges of $897,000, ($232,000) and $1,529,000, for the years ended December 31, 2014, 2013 and 2012, respectively.

As of December 31, 2014, the Company had entered into the following gas hedge contracts:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2015	Swap	30,000 Mmbtu	$3.82

At December 31, 2014, the Company had recognized an asset of approximately $8.6 million related to the estimated fair value of these derivative contracts. Based on estimated future commodity prices as of December 31, 2014, the Company would realize a $5.4 million gain, net of taxes, during the next 12 months. These gains are expected to be reclassified to oil and gas sales based on the schedule of volumes stipulated in the derivative contracts.

During January and February 2015, the Company entered into the following additional derivative contracts accounted for as a cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
February - December 2015	Swap	10,000 Mmbtu	$2.93
July 2015 - June 2016	Swap	10,000 Mmbtu	$3.22
March 2015 - December 2015	Swap	15,000 Mmbtu	$2.99
Crude Oil:			
February - December 2015	Swap (LLS)	250 Bbls	$54.00
March 2015 - December 2015	Swap (LLS)	250 Bbls	$59.35
Propane:			
March 2015 - December 2015	Swap	250 Bbls	$25.62

LLS - Louisiana Light Sweet

Derivatives designated as hedging instruments:

The following tables reflect the fair value of the Company's effective cash flow hedges in the consolidated financial statements (in thousands):

Effect of Cash Flow Hedges on the Consolidated Balance Sheet at December 31, 2014 and December 31, 2013:

	Commodity Derivatives	
Period	Balance Sheet Location	Fair Value
December 31, 2014	Derivative asset	$ 8,631
December 31, 2013	Derivative asset	$ 521
December 31, 2013	Derivative liability	$ (1,617)

Effect of Cash Flow Hedges on the Consolidated Statement of Operations for years ended December 31, 2014, 2013 and 2012:

Instrument	Amount of Gain (Loss) Recognized in Other Comprehensive Income	Location of Gain Reclassified into Income	Amount of Gain (Loss) Reclassified into Income
Commodity Derivatives at December 31, 2014	$ 6,516	Oil and gas sales	$ (3,044)
Commodity Derivatives at December 31, 2013	$ (1,617)	Oil and gas sales	$ 927
Commodity Derivatives at December 31, 2012	$ (3,510)	Oil and gas sales	$ 9,097

Derivatives not designated as hedging instruments:

The Company's three-way collar contract for 2013 gas production was not designated as an effective cash flow hedge and therefore gains and losses on this contract were recorded as derivative expense (income) in the statement of operations. The following table reflects the effect of this contract in the consolidated statements of operations (in thousands):

Effect of Non-designated Derivative Instrument on the Consolidated Statement of Operations for the years ended December 31, 2013 and 2012:

Instrument	Amount of Gain (Loss) Recognized in Derivative Income (Expense)
Commodity Derivatives at December 31, 2013	$ 233
Commodity Derivatives at December 31, 2012	$ (233)

Note 8 - Fair Value Measurements

ASC Topic 820 defines fair value 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 and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

- Level 1: valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority;
- Level 2: valuations rely on quoted prices in markets that are not active or observable inputs over the full term of the asset or liability;
- Level 3: valuations are based on prices or third party or internal valuation models that require inputs that are significant to the fair value measurement and are less observable and thus have the lowest priority.

The Company classifies its commodity derivatives based upon the data used to determine fair value. The Company's derivative instruments at December 31, 2014 and 2013 were in the form of swaps based on NYMEX pricing for oil and natural gas. The fair value of these derivatives is derived using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. As a result, the Company designates its commodity derivatives as Level 2 in the fair value hierarchy.

The following table summarizes the Company's assets (liabilities) that are subject to fair value measurement on a recurring basis as of December 31, 2014 and December 31, 2013 (in thousands):

	Fair Value Measurements Using		
Instrument	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives:			
At December 31, 2014	$ —	$ 8,631	$ —
At December 31, 2013	$ —	$ (1,096)	$ —

The fair value of the Company's cash and cash equivalents and variable-rate bank debt approximated book value at December 31, 2014 and 2013. The fair value of the Company's $350 million 10% Senior Notes due 2017 (the "Notes") was approximately $301 million and $364 million as of December 31, 2014 and 2013, respectively. The fair value of the Notes was determined based upon a market quote provided by an independent broker, which represents a Level 2 input.

Note 9—Long-Term Debt

On August 19, 2010, PetroQuest issued $150 million in principal amount of Notes (the "Existing Notes") in a public offering. On July 3, 2013, PetroQuest issued an additional $200 million in aggregate principal amount of Notes. PetroQuest subsequently registered the Notes in an exchange offer completed in September 2013 (the "New Notes" and together with the Existing Notes, the "Notes"). The New Notes were issued at a price equal to 100% of their face value plus accrued interest from March 1, 2013 and are substantially identical to the Existing Notes. The net proceeds from the offering were used to finance the $188.8 million aggregate cash purchase price of the Gulf of Mexico Acquisition, which also closed on July 3, 2013. The Notes are guaranteed by certain of PetroQuest's subsidiaries. The subsidiary guarantors are 100% owned by PetroQuest and all guarantees are full and unconditional and joint and several. PetroQuest has no independent assets or operations and the subsidiaries not providing guarantees are minor, as defined by the rules of the Securities and Exchange Commission.

The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on March 1 and September 1. At December 31, 2014, $11.7 million had been accrued in connection with the March 1, 2015 interest payment and the Company was in compliance with all of the covenants contained in the Notes.

The Company and PetroQuest Energy, L.L.C. (the "Borrower") have a Credit Agreement (as amended, the "Credit Agreement") with JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IberiaBank, Bank of America, N.A. and The Bank of Nova Scotia (collectively the "Lenders"). The Credit Agreement provides the Borrower with a $300 million revolving credit facility that permits borrowings based on the commitments of the Lenders and the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows the Borrower to use up to $25 million of the borrowing base for letters of credit. The credit facility matures on October 3, 2016. As of December 31, 2014, the Borrower had $75.0 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation of the reserves attributable to the Borrower's oil and gas properties as of January 1 and July 1 of each year. On September 29, 2014 the borrowing base was increased from $200 million to $220 million (subject to the aggregate commitments of the Lenders then in effect). As of December 31, 2014, the aggregate commitments of the Lenders is $170 million and can be increased to up to $300 million by either adding new lenders or increasing the commitments of existing Lenders, subject to certain conditions. The next borrowing base redetermination is scheduled to occur by March 31, 2015. The Borrower or the Lenders may request two additional borrowing base redeterminations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all Lenders if the borrowing base is to be increased, or by Lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The Credit Agreement is secured by a first priority lien on substantially all of the assets of the Company and its subsidiaries, including a lien on all equipment and at least 80% of the aggregate total value of the Borrower's oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate (“ABR”) plus a margin (based on a sliding scale of 0.5% to 1.5% depending on total commitments) or the adjusted LIBO rate (“Eurodollar”) plus a margin (based on a sliding scale of 1.5% to 2.5% depending on total commitments). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate plus 1%. For the purposes of the definition of alternative base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by the Borrower) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, the Borrower pays commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

The Company and its subsidiaries are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.5 to 1.0, and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0, all as defined in the Credit Agreement. The Credit Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. However, the Credit Agreement permits the Borrower to repurchase up to $10 million of the Company’s common stock during the term of the Credit Agreement, as long as after giving effect to such repurchase the Borrower’s Liquidity (as defined therein) is greater than 20% of the total commitments of the Lenders at such time. As of December 31, 2014, the Borrower was in compliance with all of the covenants contained in the Credit Agreement.

During February 2015, the Company and the Lenders amended the Credit Agreement in order to modify certain restrictive financial covenants. Specifically, the amendment removed the 3.5 to 1.0 maximum ratio of total debt to EBITDAX and replaced that with a maximum ratio of total senior secured debt to EBITDAX, determined on a rolling four quarter basis, not to exceed 2.25 to 1.0. In addition, the amendment added a minimum ratio of EBITDAX to total cash interest expense, determined on a rolling four quarter basis, of 2.0 to 1.0. The modification to the covenants described above will become effective with the quarter ended March 31, 2015 and will remain in effect through the Credit Agreement's maturity in October 2016.

Note 10—Related Party Transactions

Two of the Company’s senior officers, Charles T. Goodson and Stephen H. Green, or their affiliates, are working interest owners and overriding royalty interest owners and E. Wayne Nordberg and William W. Rucks, IV, two of the Company’s directors, are working interest owners in certain properties operated by the Company or in which the Company also holds a working interest. As working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners, they are entitled to receive their proportionate share of revenues in the normal course of business.

During 2014, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson and Green, or their affiliates, in the amounts of $80,000, and $116,000, respectively, and with respect to Mr. Nordberg, costs billed equaled revenues disbursed. During 2013, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson and Green, or their affiliates, in the amounts of $92,000 and $269,000, respectively, and with respect to Mr. Nordberg, costs billed exceeded revenues disbursed in the amount of $200. During 2012, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green and Nordberg, or their affiliates, in the amounts of $104,000, $387,000, and $100, respectively. No such disbursements were made to Mr. Rucks during any reported period. With respect to Mr. Goodson, gross revenues attributable to interests, properties or participation rights held by him prior to joining the Company as an officer and director on September 1, 1998 represent all of the gross revenue received by him during these periods.

In its capacity as operator, the Company incurs drilling and operating costs that are billed to its partners based on their respective working interests. At December 31, 2014, the Company's joint interest billing receivable included approximately $5,000 from the related parties discussed above or their affiliates, attributable to their share of costs. This represents less than 1% of the Company's total joint interest billing receivable at December 31, 2014.

Periodically, the Company charters private aircraft for business purposes. During 2014 and 2012, the Company paid approximately $18,200 and $16,900, respectively, to a third party operator in connection with the Company's use of flight hours owned by Charles T. Goodson through a fractional ownership arrangement with the third party operator. These amounts represent the cost of the hours purchased by Mr. Goodson. No such amounts were incurred during 2013. The Company's use of flight hours purchased by Mr. Goodson was pre-approved by the Company's Audit Committee and there is no agreement or obligation by or on behalf of the Company to utilize this aircraft arrangement.

Note 11—Ceiling Test Write-down

As a result of low natural gas prices and their negative impact on certain of the Company's longer-lived estimated proved reserves and estimated future net cash flows, the Company recognized a ceiling test write-down of $137.1 million during 2012. No such write-down occurred during 2014 or 2013. At December 31, 2012, the prices used in computing the estimated future net cash flows from the Company's estimated proved reserves, including the effect of hedges in place at that date, averaged $2.21 per Mcf of natural gas, $102.81 per barrel of oil and $6.07 per Mcfe of Ngl. The Company's cash flow hedges in place decreased the ceiling test write-down by approximately $2.2 million.

Note 12—Other Comprehensive Income

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the year ended December 31, 2013 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of December 31, 2012	$ 521	$ —	$ 521
Other comprehensive loss before reclassifications:			
Change in fair value of derivatives	(999)		(999)
Income tax effect	372	(408)	(36)
Net of tax	(627)	(408)	(1,035)
Amounts reclassified from accumulated other comprehensive income:			
Oil and gas sales	(927)		(927)
Income tax effect	345	—	345
Net of tax	(582)	—	(582)
Net other comprehensive loss	(1,209)	(408)	(1,617)
Balance as of December 31, 2013	$ (688)	$ (408)	$ (1,096)

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the year ended December 31, 2014 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of December 31, 2013	$ (688)	$ (408)	$ (1,096)
Other comprehensive loss before reclassifications:			
Change in fair value of derivatives	6,683		6,683
Income tax effect	(2,487)	408	(2,079)
Net of tax	4,196	408	4,604
Amounts reclassified from accumulated other comprehensive income:			
Oil and gas sales	3,044		3,044
Income tax effect	(1,132)	—	(1,132)
Net of tax	1,912	—	1,912
Net other comprehensive loss	6,108	408	6,516
Balance as of December 31, 2014	$ 5,420	$ —	$ 5,420

See Note 7 for additional details about the effect of the above reclassifications.

Note 13—Income Taxes

The Company typically provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes. As a result of the ceiling test write-downs recognized during 2011 and 2012, the Company incurred a cumulative three-year loss. Because of the impact the cumulative loss had on the determination of the recoverability of deferred tax assets through future earnings, the Company assessed the realizability of its deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, the Company established a valuation allowance of $33.3 million as of December 31, 2014.

An analysis of the Company's deferred taxes follows (amounts in thousands):

	December 31,		
	2014	2013	2012
Net operating loss carryforwards	$ 17,705	$ 21,810	$ 16,641
Percentage depletion carryforward	10,206	8,645	7,317
Alternative minimum tax credits	784	784	784
Contributions carryforward and other	241	189	156
Temporary differences:			
Oil and gas properties	(15,439)	(7,248)	12,575
Asset retirement obligation	20,449	18,056	10,141
Derivatives	(3,211)	408	(222)
Share-based compensation	2,560	2,887	3,474
Valuation allowance	(33,295)	(45,531)	(50,866)
Deferred taxes	$ —	$ —	$ —

At December 31, 2014, the Company had approximately $60.2 million of operating loss carryforwards, of which $12.6 million relates to excess tax benefits with respect to share-based compensation that have not been recognized in the financial statements. If not utilized, approximately $8.7 million of such carryforwards would expire in 2025 and the remainder would expire by the year 2034. The Company has available for tax reporting purposes $29.2 million in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2014, 2013 and 2012 was different than the amount computed using the Federal statutory rate (35%) for the following reasons (amounts in thousands):

	For the Year Ended December 31,		
	2014	2013	2012
Amount computed using the statutory rate	$ 9,887	$ 5,041	$ (45,655)
Increase (reduction) in taxes resulting from:			
State & local taxes	904	317	(2,870)
Percentage depletion carryforward	(1,564)	(1,323)	(1,309)
Non-deductible stock option expense (1)	213	115	292
Share-based compensation (2)	90	780	9
Other	(643)	1,132	303
Change in valuation allowance	(11,828)	(5,742)	50,866
Income tax expense (benefit)	$ (2,941)	$ 320	$ 1,636

(1) Relates to compensation expense recognized on the vesting of Incentive Stock Options.
(2) Relates to the write-off of deferred tax assets associated with share-based compensation that will not be deductible for tax purposes.

Note 14—Commitments and Contingencies

The Company is a party to ongoing litigation in the normal course of business. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management believes that the effect on its financial condition, results of operations and cash flows, if any, will not be material.

Lease Commitments

The Company has operating leases for office space and equipment, which expire on various dates through 2023. Future minimum lease commitments as of December 31, 2014 under these operating leases are as follows (in thousands):

2015	$ 1,480
2016	1,418
2017	1,317
2018	416
2019	401
Thereafter	1,631
	$ 6,663

Total rent expense under operating leases was approximately $1.6 million, $1.4 million and $1.4 million in 2014, 2013 and 2012, respectively.

Note 15—Supplementary Information on Oil and Gas Operations—Unaudited

The following tables disclose certain financial data relative to the Company's oil and gas producing activities, which are located onshore and offshore in the continental United States:

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
(*amounts in thousands*)

	For the Year-Ended December 31, 2014	2013	2012
Acquisition costs:			
Proved (1)	$ 3,064	$ 177,880	$ 352
Unproved (1)	39,164	35,008	15,677
Divestitures—unproved (2)	(3,298)	(487)	(8,889)
Exploration costs:			
Proved	67,297	34,344	72,361
Unproved	13,515	20,112	18,033
Development costs	55,722	41,328	18,740
Capitalized general and administrative and interest costs	22,121	19,911	18,961
Total costs incurred	$ 197,585	$ 328,096	$ 135,235

	For the Year-Ended December 31, 2014	2013	2012
Accumulated depreciation, depletion and amortization (DD&A)			
Balance, beginning of year	$ (1,553,044)	$ (1,472,244)	$ (1,265,603)
Provision for DD&A	(86,406)	(69,357)	(59,496)
Ceiling test writedown	—	—	(137,100)
Sale of proved properties and other (3)	(8,610)	(11,443)	(10,045)
Balance, end of year	$ (1,648,060)	$ (1,553,044)	$ (1,472,244)
DD&A per Mcfe	$ 1.99	$ 1.82	$ 1.75

(1) During 2014, the Company entered into a joint venture in Louisiana for an aggregate purchase price of $24 million for an approximate 30,000 acre leasehold position. During 2013, the Company closed on the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million (see Note 2). Additionally, the Company acquired 13,500 net unevaluated acres in Oklahoma targeting the Woodford Shale in 2013.

(2) During 2012, the Company sold an additional portion of its Mississippian Lime acreage for $6.1 million.

(3) During 2014, the Company sold its Eagle Ford assets for net proceeds of approximately $9.8 million. During 2013, the Company sold 50% of its saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10.4 million and its non-operated Wyoming assets for a cash purchase price of $1.0 million. During 2012, the Company sold its non-operated Arkansas assets for a net cash purchase price of $8.5 million.

At December 31, 2014 and 2013, unevaluated oil and gas properties totaled $109.1 million and $98.4 million, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2014 included $16.8 million of costs related to 16 exploratory wells in progress at year-end. These costs are expected to be transferred to evaluated oil and gas properties during 2015 upon the completion of drilling. At December 31, 2013, unevaluated costs included $11.3 million related to 19 exploratory wells in progress. All of these costs were transferred to evaluated oil and gas properties during 2014. The Company capitalized $10.0 million, $6.6 million and $7.0 million of interest during 2014, 2013 and 2012, respectively. Of the total unevaluated oil and gas property costs of $109.1 million at December 31, 2014, $56.3 million, or 52%, was incurred in 2014, $21.1 million, or 19%, was incurred in 2013 and $31.7 million, or 29%, was incurred in prior years. The Company expects that the majority of the unevaluated costs at December 31, 2014 will be evaluated within the next 3 years, including $32.5 million that the Company expects to be evaluated during 2015.

Oil and Gas Reserve Information

The Company's net proved oil and gas reserves at December 31, 2014 have been estimated by independent petroleum engineers in accordance with guidelines established by the SEC using a historical 12-month average pricing assumption.

The estimates of proved oil and gas reserves constitute those quantities of oil, gas,and natural gas liquids, 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. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. In addition, the present values should not be construed as the current market value of the Company's oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

The following table sets forth an analysis of the Company's estimated quantities of net proved and proved developed oil (including condensate), gas and natural gas liquid reserves, all located onshore and offshore in the continental United States:

	Oil in MBbls	NGL in MMcfe	Natural Gas in MMcf	Total Reserves in MMcfe
Proved reserves as of December 31, 2011	1,395	15,111	241,926	265,407
Revisions of previous estimates (1)	195	(1,952)	(56,780)	(57,561)
Extensions, discoveries and other additions	647	14,572	46,390	64,844
Sale of reserves in place	(81)	—	(15,806)	(16,292)
Production	(521)	(3,365)	(27,466)	(33,957)
Proved reserves as of December 31, 2012	1,635	24,366	188,264	222,441
Revisions of previous estimates (1)	(156)	804	38,383	38,247
Extensions, discoveries and other additions	434	6,099	30,429	39,132
Purchase of producing properties	1,833	1,915	22,274	35,187
Sale of reserves in place	(34)	—	(15)	(218)
Production	(681)	(4,754)	(29,226)	(38,066)
Proved reserves as of December 31, 2013	3,031	28,430	250,109	296,723
Revisions of previous estimates	(37)	2,894	9,976	12,650
Extensions, discoveries and other additions	475	49,990	82,364	135,205
Purchase of producing properties	—	—	—	—
Sale of reserves in place	(229)	(334)	(2,396)	(4,105)
Production	(803)	(7,482)	(31,028)	(43,325)
Proved reserves as of December 31, 2014	2,437	73,498	309,025	397,148
Proved developed reserves				
As of December 31, 2012	1,225	20,608	140,307	168,265
As of December 31, 2013	2,709	23,173	163,728	203,152
As of December 31, 2014	2,089	42,584	182,567	237,688
Proved undeveloped reserves				
As of December 31, 2012 (1)	410	3,758	47,957	54,176
As of December 31, 2013 (1)	322	5,257	86,381	93,571
As of December 31, 2014	348	30,914	126,458	159,460

(1) The table above includes certain adjustments to previously disclosed estimated proved reserves as of December 31, 2013 and 2012. Specifically, as of December 31, 2014, the Company determined that it should have reflected additional downward revisions to certain of its proved undeveloped reserves totaling 5,088 MMcfe and 5,817 MMcfe as of December 31, 2013 and 2012, respectively. The table above reflects such adjustments of previous estimates for the years ended December 31, 2013 and 2012, respectively. The above adjustments had no material impact on the Company's financial statements for the years ended December 31, 2013 and 2012.

Year Ended December 31, 2014

During 2014, the Company's estimated proved reserves increased by 34%. Extensions, discoveries and other additions of 135 Bcfe were primarily due to successful drilling programs in the Company's Oklahoma and East Texas fields and its Thunder Bayou discovery. The Company added approximately 72 Bcfe of proved reserves in Oklahoma, 46 Bcfe in Texas and 15 Bcfe in the Gulf Coast. Overall, the Company had a 91% drilling success rate during 2014 on 58 gross wells drilled.

Year Ended December 31, 2013

Extensions, discoveries and other additions were primarily due to the success of the Company's Oklahoma, Texas and Gulf Coast drilling programs. The Company added approximately 23 Bcfe of proved reserves in Oklahoma, 5 Bcfe in the Gulf Coast and 10 Bcfe in Texas. Revisions of previous estimates were primarily a result of the increase in the historical 12-month average price per Mcf of natural gas used to calculate estimated proved reserves, which was $3.11 per Mcf at December 31, 2013 as compared to $2.20 per Mcf at December 31, 2012. The 35 Bcfe added through purchase of producing properties relates to the Company's Gulf of Mexico Acquisition (See Note 2).

Year Ended December 31, 2012

Extensions, discoveries and other additions were primarily due to the success the Company's Oklahoma, Texas and Gulf Coast drilling programs. The Company added approximately 27 Bcfe of proved reserves in Oklahoma, 9 Bcfe from the La Cantera discovery in the Gulf Coast and 27 Bcfe in the Carthage Field in Texas from horizontal drilling in the Cotton Valley. Revisions of previous estimates were primarily a result of the significant decrease in the historical 12-month average price per Mcf of natural gas used to calculate estimated proved reserves, which was $2.20 per Mcf at December 31, 2012 as compared to $3.34 per Mcf at December 31, 2011. Sale of reserves in place primarily related to the divestiture of the Company's non-operated Arkansas assets.

The following tables (amounts in thousands) present the standardized measure of future net cash flows related to proved oil and gas reserves together with changes therein, as defined by ASC Topic 932. Future production and development costs are based on current costs with no escalations. Estimated future cash flows have been discounted to their present values based on a 10% annual discount rate.

Standardized Measure

	December 31,		
	2014	2013 (1)	2012 (1)
Future cash flows	$ 1,711,404	$ 1,243,627	$ 728,878
Future production costs	(372,690)	(295,666)	(215,195)
Future development costs	(244,784)	(185,188)	(110,825)
Future income taxes	(121,192)	(37,404)	(9,642)
Future net cash flows	972,738	725,369	393,216
10% annual discount	(424,176)	(274,189)	(162,393)
Standardized measure of discounted future net cash flows	$ 548,562	$ 451,180	$ 230,823

Changes in Standardized Measure

	Year Ended December 31,		
	2014	2013 (1)	2012 (1)
Standardized measure at beginning of year	$ 451,180	$ 230,823	$ 303,881
Sales and transfers of oil and gas produced, net of production costs	(173,540)	(134,184)	(92,562)
Changes in price, net of future production costs	37,204	55,601	(140,230)
Extensions and discoveries, net of future production and development costs	237,290	70,181	104,066
Changes in estimated future development costs, net of development costs incurred during this period	11,094	(25,389)	77,188
Revisions of quantity estimates	25,591	58,508	(62,159)
Accretion of discount	47,130	23,776	34,137
Net change in income taxes	(32,034)	(13,182)	30,559
Purchase of reserves in place	—	191,964	—
Sale of reserves in place	(7,240)	(411)	(8,186)
Changes in production rates (timing) and other	(48,113)	(6,507)	(15,871)
Net increase (decrease) in standardized measure	97,382	220,357	(73,058)
Standardized measure at end of year	$ 548,562	$ 451,180	$ 230,823

(1) The table above includes certain adjustments to previously disclosed estimated proved reserves as of December 31, 2013 and 2012. Specifically, as of December 31, 2014, the Company determined that it should have reflected additional downward revisions to certain of its proved undeveloped reserves totaling 5,088 MMcfe and 5,817 MMcfe as of December 31, 2013 and 2012, respectively. The table above reflects such adjustments of previous estimates for the years ended December 31, 2013 and 2012, respectively. The above adjustments had no material impact on the Company's financial statements for the years ended December 31, 2013 and 2012.

The historical twelve-month average prices of oil, gas and natural gas liquids used in determining standardized measure were:

	2014	2013	2012
Oil, $/Bbl	$96.45	$106.19	$102.81
Ngls, $/Mcfe	4.11	5.10	6.07
Natural Gas, $/Mcf	3.80	3.11	2.20

Note 16 - Summarized Quarterly Financial Information - Unaudited

Summarized quarterly financial information is as follows (amounts in thousands except per share data):

	Quarter Ended			
	March 31	June 30	September 30	December 31
2014:				
Revenues	$ 59,966	$ 60,581	$ 56,486	$ 47,988
Income from operations	11,323	10,879	5,569	478
Income available to common stockholders	10,043	9,592	4,671	1,745
Earnings per share:				
Basic	$ 0.15	$ 0.15	$ 0.07	$ 0.03
Diluted	$ 0.15	$ 0.15	$ 0.07	$ 0.03
2013:				
Revenues	$ 35,976	$ 38,076	$ 55,578	$ 53,174
Income from operations	4,236	4,109	1,687	4,370
Income available to common stockholders	2,607	3,662	383	2,291
Earnings per share:				
Basic	$ 0.04	$ 0.06	$ 0.01	$ 0.04
Diluted	$ 0.04	$ 0.06	$ 0.01	$ 0.04

CORPORATE INFORMATION

BOARD OF DIRECTORS

Charles T. Goodson
Chairman of the Board,
Chief Executive Officer, and President

W.J. Gordon III *#^
Vice President of Strategic Planning Franciscan Missionaries of Our Lady Health System

Michael L. Finch *#^
Private Investments

Charles F. Mitchell II, M.D. *#^
Physician, Private Investments

E. Wayne Nordberg *#^
Hollow Brook Associates, LLC

William W. Rucks, IV *#^
Private Investments

* Member of the Compensation Committee
# Member of the Audit Committee
^ Member of the Nominating and Corporate Governance Committee

SENIOR MANAGEMENT

Charles T. Goodson
Chairman of the Board,
Chief Executive Officer, and President

W. Todd Zehnder
Chief Operating Officer

J. Bond Clement
Executive Vice President,
Chief Financial Officer, and Treasurer

Art M. Mixon
Executive Vice President
Operations and Production

Tracy Price
Executive Vice President
Business Development & Land

Edward E. Abels, Jr.
Executive Vice President, General Counsel,
and Corporate Secretary

Stephen H. Green
Senior Vice President
Exploration

Mark K. Castell
Vice President - Oklahoma Assets

Edgar A. Anderson
Vice President - ArkLaTex

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Fax: (281) 465-3999

1717 S. Boulder, Suite 201
Tulsa, Oklahoma 74119
Telephone: (918) 582-2770
Fax: (918) 582-2778

TRANSFER AGENT AND REGISTRAR

American Stock Transfer & Trust Company
59 Maiden Lane
New York, New York 10038
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INDEPENDENT AUDITORS

Ernst & Young LLP
New Orleans, Louisiana 70170

LEGAL COUNSEL

Porter Hedges LLP
Houston, Texas 77002

Onebane Law Firm
Lafayette, Louisiana 70508

ANNUAL MEETING

The Company's Annual Meeting of Stockholders will be held at 9:00 A.M. CDT on May 20, 2015, at the City Club at River Ranch at 221 Elysian Fields Drive, Lafayette, Louisiana, 70508.

FORM 10-K

Copies of the Company's Annual Report on Form 10-K may be obtained, without charge, by writing to our Corporate Secretary at our Corporate Address or on the Company's website at www.petroquest.com.

COMMON STOCK LISTING

Listed on NYSE as PQ

PetroQuest Energy, Inc.

WWW.PETROQUEST.COM

NYSE:PQ