HALCON RESOURCES CORP
Form 10-K
February 27, 2014

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2013

Commission File Number: 001-35467

Halcón Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	**20-0700684**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

1000 Louisiana Street, Suite 6700, Houston, TX 77002
(Address of principal executive offices)
(832) 538-0300
(Registrant's telephone number)

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 $.0001 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 ý No o

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 o No ý

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 ý No o

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 ý No o

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

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 definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of February 24, 2014, there were 415,686,264 shares outstanding of registrant's $.0001 par value common stock. Based upon the closing price for the registrant's common stock on the New York Stock Exchange as of June 30, 2013, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately $1.1 billion.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13, and 14, is incorporated by reference to portions of the registrant's definitive proxy statement for its 2014 annual meeting of stockholders which will be filed no later than 120 days after December 31, 2013.

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Special note regarding forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number and location of wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "objective," "believe," "predict," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. Readers should consider carefully the risks described under the "Risk Factors" section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, including, but not limited to, the following factors:

- our ability to successfully integrate acquired oil and natural gas businesses and operations;
- the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions will not achieve intended benefits and will divert management's time and energy, which could have an adverse effect on our financial position, results of operations, or cash flows;
- risks in connection with potential acquisitions and the integration of significant acquisitions;
- we have substantial indebtedness and may incur more debt; higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business;
- our ability to successfully develop our large inventory of undeveloped acreage in our resource plays;
- access to and availability of water and other treatment materials to carry out planned fracture stimulations in our resource plays;
- access to adequate gathering systems, processing facilities, transportation take-away capacity to move our production to market and marketing outlets to sell our production at market prices, which is necessary to fully execute our capital program;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and fully develop our undeveloped acreage positions;
- volatility in commodity prices for oil and natural gas;
- our ability to replace our oil and natural gas reserves;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;

contractual limitations that affect our management's discretion in managing our business, including covenants that, among other things, limit our ability to incur debt, make investments and pay cash dividends;

the potential for production decline rates for our wells to be greater than we expect;

our ability to retain key members of senior management and key technical employees;

competition, including competition for acreage in resource play holdings;

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- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulations);
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or acts of terrorism or sabotage;
- other economic, competitive, governmental, regulatory, legislative, including federal, state and tribal regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;
- the insurance coverage maintained by us may not adequately cover all losses that may be sustained in connection with our business activities;
- title to the properties in which we have an interest may be impaired by title defects;
- senior management's ability to execute our plans to meet our goals;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars; and
- our dependency on the skill, ability and decisions of third party operators of the oil and natural gas properties in which we have a non-operated working interest.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

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Glossary of Oil and Natural Gas Terms

The definitions set forth below apply to the indicated terms as used in this report. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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

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

Dry hole or well. 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.

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

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

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.

Hydraulic fracturing. The injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production.

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

MBoe. One thousand Boe.

MMBoe. One million Boe.

Mcf. One thousand cubic feet of natural gas.

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

MMBtu. One million Btu.

MMcf. One million cubic feet of natural gas.

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

Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease.

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.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.

Proved developed reserves. Proved reserves that are expected to be recovered from existing wellbores, whether or not currently producing, without drilling additional wells. Production of such reserves may require a recompletion.

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

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

Proved undeveloped reserves. Proved reserves 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.

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

Reserve-to-production ratio or Reserve life. A ratio determined by dividing our estimated existing reserves determined as of the stated measurement date by production from such reserves for the prior twelve month period.

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

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

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 oil and natural gas regardless of whether such acreage contains proved reserves.

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

Workover. Operations on a producing well to restore or increase production.

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PART I

ITEM 1. BUSINESS

Overview

Unless the context otherwise requires, all references in this report to "Halcón," "our," "us," and "we" refer to Halcón Resources Corporation (formerly known as RAM Energy Resources, Inc.) and its subsidiaries, as a common entity.

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. We were incorporated in Delaware on February 5, 2004 and were recapitalized on February 8, 2012, as described more fully herein. During 2012, we focused our efforts on the acquisition of unevaluated leasehold and producing properties in selected prospect areas, providing us with an extensive drilling inventory in multiple basins that we believe allow for multiple years of production growth and broad flexibility to direct our capital resources to projects with the greatest potential returns. During 2013, we focused on the development of acquired properties and also divested non-core assets in order to fund activities in our core resource plays.

At December 31, 2013, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell), were approximately 136 MMBoe, consisting of 114.5 MMBbls of oil, 9.8 MMBbls of natural gas liquids, and 69.7 Bcf of natural gas. Approximately 40% of our proved reserves were classified as proved developed. We maintain operational control of approximately 92% of our proved reserves.

Our oil and natural gas assets consist of undeveloped acreage positions in unconventional liquids-rich basins/fields. We have acquired acreage and may acquire additional acreage in the Bakken / Three Forks formations in North Dakota, the Eagle Ford formation in East Texas, the Utica / Point Pleasant formations in Ohio and Pennsylvania and the Tuscaloosa Marine Shale formation in Mississippi and Louisiana, as well as several other areas.

Our total operating revenues for 2013 were approximately $999.5 million. Production for the fourth quarter of 2013 averaged 40,217 Boe/d. Pro forma for the divestitures of certain non-core assets, production for the fourth quarter of 2013 averaged 37,489 Boe/d. Full year 2013 production averaged 33,329 Boe/d compared to 9,404 Boe/d in 2012, resulting in a 254% year over year increase in our average daily production. The increase in production compared to the prior year period was driven by our operated drilling results and increased production volumes associated with the development of properties we acquired in 2012 in the Bakken / Three Forks, Woodbine, and the Eagle Ford formation in East Texas (which we refer to as "El Halcón"). These areas collectively accounted for approximately 25,764 Boe/d, or 77% of our production in 2013. Our remaining production was associated with various non-core properties, many of which have since been divested. In 2013, we participated in the drilling of 284 gross (107.4 net) wells of which 281 gross (104.4 net) wells were completed and capable of production, and 3 gross (3.0 net) wells were dry holes.

Recent Developments

Divestitures of Non-core Assets

During the second half of 2013, we entered into three separate purchase and sale agreements with unrelated parties to divest certain non-core assets located throughout the United States for total consideration of approximately $302.0 million, all three of which closed in the fourth quarter of 2013. In aggregate, as of December 31, 2012, estimated proved reserves associated with these non-core assets, were approximately 21.2 MMBoe (69% oil). Production from these non-core assets averaged approximately 4,400 Boe/d during the third quarter of 2013. Proceeds from the sales of the non-core

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assets were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The borrowing base reduction associated with these non-core asset sales was $50.0 million. Following the closing of the last of these three divestitures, on December 20, 2013, the borrowing base under our Senior Credit Agreement was reduced by the $50.0 million to $700.0 million.

Issuance of Additional 9.75% Senior Notes

On December 19, 2013, we issued an additional $400.0 million aggregate principal amount of our 9.75% senior notes due 2020. The net proceeds from the sale of the additional 2020 Notes of approximately $406.1 million were used to repay a portion of the then outstanding borrowings under our Senior Credit Agreement. In total, we have issued $1.15 billion of 9.75% senior notes due 2020. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Long-Term Debt"* for additional information on the additional 2020 Notes.

Issuance of 9.25% Senior Notes and Common Stock

On August 13, 2013, we issued $400.0 million aggregate principal amount of 9.25% senior notes due 2022. The net proceeds from the offering of approximately $392.1 million were used to repay a portion of the then outstanding borrowings on our Senior Credit Agreement. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Long-Term Debt"* for additional information on the 2022 Notes.

On August 13, 2013, we also completed the issuance of 43.7 million shares of common stock in an underwritten public offering. The net proceeds from the offering of common stock of approximately $215.2 million were used to repay a portion of the then outstanding borrowings on our Senior Credit Agreement. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 11,*"Preferred Stock and Stockholders' Equity"* for additional information on the common stock offering.

Divestiture of Eagle Ford Assets

On July 19, 2013, we completed the sale of our interest in Eagle Ford assets in Fayette and Gonzales Counties, Texas to private buyers for proceeds of approximately $147.9 million, before post-closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. As of December 31, 2012, we had approximately 3.6 MMBoe of estimated proved reserves associated with these properties. Production from the Eagle Ford assets averaged approximately 1,811 Boe/d during the second quarter of 2013.

Issuance of 5.75% Series A Convertible Perpetual Preferred Stock

On June 18, 2013, we issued in a public offering 345,000 shares of 5.75% Series A Convertible Perpetual Preferred Stock (the Series A Preferred Stock). The net proceeds of approximately $335.5 million were used to repay a portion of the then outstanding borrowings under our Senior Credit Agreement. Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, cumulative dividends at the rate of 5.75% per annum on the $1,000 liquidation preference per share of the Series A Preferred Stock, payable quarterly in arrears on each dividend payment date. Dividends may be paid in cash or, where freely transferable by any non-affiliate recipient thereof, in shares of common stock or a combination thereof, and are payable on March 1, June 1, September 1 and December 1 of each year. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 11,*"Preferred Stock and Stockholders' Equity"* for additional information on the Series A Preferred Stock.

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Issuance of Additional 8.875% Senior Notes

On January 14, 2013, we issued an additional $600.0 million aggregate principal amount of our 8.875% senior notes due 2021. The net proceeds of approximately $619.5 million were used to repay a portion of the then outstanding borrowings on our Senior Credit Agreement and for general corporate purposes. In total, we have issued $1.35 billion of 8.875% senior notes due 2021. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Long-Term Debt"* for additional information on the 2021 Notes.

Amendments to Senior Credit Agreement and Borrowing Base

On October 31, 2013, we entered into the Sixth Amendment to our Senior Credit Agreement. The Sixth Amendment established our borrowing base at $850.0 million, which has since been reduced to $700.0 million upon the closing of the final non-core divestiture in December 2013. Additionally, the Sixth Amendment provides for EBITDA (as defined in the Senior Credit Agreement) to be annualized for purposes of measuring compliance with the interest coverage test under the Senior Credit Agreement. Specifically, (i) for the fiscal quarter ended December 31, 2013, the Interest Coverage Ratio will be calculated by utilizing EBITDA for the three month period then ended multiplied by 4; (ii) for the fiscal quarter ended March 31, 2014, the Interest Coverage Ratio will be calculated by utilizing EBITDA for the six month period then ended multiplied by 2; and (iii) for the fiscal quarter ended June 30, 2014, the Interest Coverage Ratio will be calculated by utilizing EBITDA for the nine month period then ended multiplied by 1.333.

On June 11, 2013, we entered into the Fifth Amendment to the Senior Credit Agreement which permits us, among other things, to pay cash dividends to holders of our preferred capital stock. On May 8, 2013, we entered into the Fourth Amendment to the Senior Credit Agreement which modified the calculation of the interest coverage test, which was superseded by the Sixth Amendment. On April 26, 2013, we entered into the Third Amendment to our Senior Credit Agreement, which, among other things, provided additional flexibility under certain affirmative and negative covenants and on January 25, 2013, we entered into the Second Amendment to our Senior Credit Agreement which expanded our ability to enter into certain commodity hedging agreements.

2014 Capital Budget

We expect to spend approximately $950 million on drilling and completion capital expenditures during 2014. Approximately 49% of our 2014 drilling and completions budget is expected to be spent in the Bakken / Three Forks formations in North Dakota, approximately 40% is budgeted for the El Halcón area in East Texas, and the remaining amount is planned for various other project areas, including the Tuscaloosa Marine Shale in Louisiana and Mississippi and the Utica / Point Pleasant formations in Ohio. Our 2014 drilling and completion budget contemplates four to five operated rigs running in the Bakken / Three Forks, three to four operated rigs running in the El Halcón area and one to two operated rigs running in the other areas. Our drilling and completion budget for 2014 is based on our current view of market conditions and current business plans, and is subject to change.

We expect to fund our budgeted 2014 capital expenditures with cash flows from operations, proceeds from additional potential non-core asset divestitures and borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position. In the event our cash flows or proceeds from additional potential non-core asset dispositions are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending.

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Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominately upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves in an economical manner is critical to our long-term success.

Business Strategy

Our primary objective is to increase stockholder value by growing reserves, production and cash flow. To accomplish this objective, we intend to execute the following business strategies:

Develop and Grow Our Liquids Rich Resource-Style Acreage Positions Using Our Proven Development Expertise. We plan to leverage our management team's expertise and the latest available technologies to economically develop our property portfolio with a focus on our core liquids-rich resource style plays. We expect to be the operator for the majority of our acreage, which gives us control over the timing of capital expenditures, execution and costs. It also allows us to adjust our capital spending based on drilling results and the economic environment. Our leasing strategy is to pursue long-term contracts that allow us to maintain flexible development plans and avoid short-term obligations to drill wells, as have been common in other resource plays. As operator, we are also able to evaluate industry drilling results and implement improved operating practices which may enhance our initial production rates, ultimate recovery factors and rate of return on invested capital.

Manage Our Property Portfolio Actively. We continually evaluate our property base to identify and divest non-core assets and, higher cost or lower volume producing properties with limited development potential, which allows us to focus on a portfolio of core properties with significant potential to increase our proved reserves and production. Divestitures of non-core assets provide us with cash to reinvest in our business and repay debt, reducing our reliance on capital markets for financing.

Maintain Strong Balance Sheet and Financial Flexibility. We believe our cash, internally generated cash flows, borrowing capacity, non-core asset sales and access to capital markets will provide us with sufficient liquidity to execute our current capital program and strategy. We have no near term debt maturities. Our management team has a successful track record of issuing equity and debt, and selling non-core assets to maintain a strong balance sheet. Since February 2012, we have issued in the aggregate approximately $6.0 billion of equity and debt securities. We also employ a hedging program to reduce the variability of our cash flows used to support our capital spending.

Our Competitive Strengths

We have a number of competitive strengths that we believe will allow us to successfully execute our business strategies:

Proven Management Team with Significant Ownership Stake. Our management team and technical professionals, including geologists and engineers, have decades of combined experience in the industry. Our management team has successfully founded, grown, operated and sold companies in this industry sector. Floyd C. Wilson was Chairman and Chief Executive Officer of Petrohawk Energy Corporation, which was acquired by BHP Billiton in August 2011, Chairman and Chief Executive Officer of 3TEC Energy Corporation, which was acquired by Plains Exploration &

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Production Company in 2003, and Chairman and Chief Executive Officer of Hugoton Energy Corporation, which was acquired by Chesapeake Energy Corporation in 1998.

Geographically and Geologically Diverse Asset Base. Our proved reserves, production and acreage are located in concentrated positions within multiple onshore U.S. basins. These various basins provide exposure to a variety of reservoir formations, each of which has its own characteristics that impact the costs to drill, complete and operate as well as the composition (and therefore value) of the hydrocarbon stream. We believe that this geographic diversity provides us with broad flexibility to direct our capital resources to projects with the greatest potential returns and access to multiple key end markets, which mitigates our exposure to temporary price dislocations in any one market.

Extensive Experience in Resource Plays. Our team has significant experience in all aspects of the development of resource plays. Under Mr. Wilson's leadership, Petrohawk, 3TEC and Hugoton improved drilling times and reserve recoveries through innovation, the use of new technologies and a focus on controlling costs. While at Petrohawk, in developing the early shale plays, the technical team also acquired expertise relevant in our evaluation of new resource play opportunities. In addition to their core strength in exploration and production, our personnel have experience in building midstream infrastructure and have managed oilfield service activities. For example, Petrohawk developed extensive midstream systems serving the Eagle Ford Shale and the Haynesville Shale in order to accommodate their rapid growth in production volumes.

Strong Technical Team. We believe that there are certain competitive advantages to be gained by employing a highly skilled technical staff. Our technical staff (including field personnel) currently represents a majority of our employee base. This team has significant experience and expertise in applying the most sophisticated technologies used in conventional and unconventional resource style plays, including 3-D seismic interpretation, horizontal drilling, deep onshore drilling, comprehensive multi-stage hydraulic fracture stimulation programs, and other exploration, production, and processing technologies. We believe this technical expertise is partly responsible for our management team's strong track record of successful exploration and development, including new discoveries and defining core producing areas in emerging plays.

Oil and Natural Gas Reserves

The reserves estimates shown herein for the years ended December 31, 2013 and 2012 have been independently evaluated by Netherland, Sewell, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland, Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserves report incorporated herein are Mr. J. Carter Henson, Jr. and Mr. Mike K. Norton. Mr. Henson has been practicing consulting petroleum engineering at Netherland, Sewell since 1989. Mr. Henson is a Licensed Professional Engineer in the State of Texas (No. 73964) and has over 30 years of practical experience in petroleum engineering, with over 24 years' experience in the estimation and evaluation of reserves. He graduated from Rice University in 1981 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Norton has been practicing consulting petroleum geology at Netherland, Sewell since 1989. Mr. Norton is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441) and has over 30 years of practical experience in petroleum geosciences, with over 24 years' experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience

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evaluations as well as applying Securities and Exchange Commission (SEC) and other industry reserves definitions and guidelines. Our estimated proved reserves for the year ended December 31, 2011 were prepared by Forrest A. Garb & Associates, an independent oil and natural gas reservoir engineering consulting firm.

Our board of directors has established a reserves committee composed of four independent directors, all of whom have experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Vice President of Corporate Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to our board of directors as to whether to accept the report prepared by our independent consulting petroleum engineers. In 2013, Ms. Tina Obut, our Vice President of Corporate Reserves was the technical person primarily responsible for overseeing the preparation of the annual reserve report by Netherland, Sewell. She graduated from Marietta College with a Bachelor of Science degree in Petroleum Engineering, received a Master of Science degree in Petroleum and Natural Gas Engineering from Penn State University and a Master of Business Administration degree from the University of Houston.

The reserves information in this Annual Report on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve evaluation is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary significantly. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell and other information about our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data* "*Supplemental Oil and Gas Information (Unaudited)*."

Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month for the 12-month period ended December 31, 2013. Average prices for the 12-month period were as follows: West Texas Intermediate (WTI) spot price of $96.94 per barrel (Bbl), adjusted by lease or field for quality, transportation fees, and regional price differentials and a Henry Hub spot price of $3.670 per MMBtu, as adjusted by lease or field for energy content, transportation fees, and regional price differentials. All prices and costs associated with operating wells were held constant in accordance with the amended SEC guidelines. The following table presents certain proved reserve information as of December 31, 2013.

	Total
Proved Reserves at Year End (MBoe)[(1)]	
Developed	54,605
Undeveloped	81,362
Total	135,967

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(1) Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

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The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2013 and 2012. Shut-in wells currently not capable of production are excluded from producing well information.

	Years Ended December 31,			
	2013		2012	
	Gross	Net	Gross	Net
Oil	1,086	259.0	2,428	1,396.0
Natural Gas	149	86.5	893	425.6
Total	1,235	345.5	3,321	1,821.6

Oil and Natural Gas Production

Core Resource Plays

At December 31, 2013, we have estimated proved reserves in our core resource plays of approximately 113.2 MMBoe, of which 95% are oil and natural gas liquids and 38% are proved developed. In general, our core resource plays are characterized by high oil and liquids-rich natural gas content in thick, continuous sections of source rock that can provide repeatable drilling opportunities and significant initial production rates. Our core resource plays are as follows:

Bakken / Three Forks Formations

We have working interests in approximately 149,000 net acres as of December 31, 2013 prospective for the Bakken / Three Forks formations in North Dakota. Multiple initiatives are underway to lower costs and improve recoveries in our operated project areas. We expect to spud 40 to 50 gross horizontal wells on our operated acreage in 2014 with an average working interest of approximately 68%. In 2014, we expect to operate four to five rigs in the Williston Basin. As of December 31, 2013, we had approximately 171 operated wells producing in this area in addition to minor working interests in hundreds of non-operated wells. Our average daily net production from this area for the three months ended December 31, 2013 was 24,125 Boe/d. As of December 31, 2013, estimated proved reserves for the Bakken / Three Forks formations were approximately 90.5 MMBoe, of which approximately 40% were classified as proved developed and approximately 60% as proved undeveloped.

East Texas Eagle Ford Formation (El Halcón)

We have working interests in approximately 94,000 net acres as of December 31, 2013 prospective for the El Halcón areas in Brazos, Burleson, and Lee Counties, Texas, with targeted depths ranging from 7,000 feet to 10,000 feet. We finished 2013 with a four rig drilling program and approximately 40 producing wells. In 2014, we plan to operate three to four rigs and spud 40 to 50 gross horizontal wells with an average working interest of approximately 83%. Our average daily net production from this area for the three months ended December 31, 2013 was 7,138 Boe/d. As of December 31, 2013, estimated proved reserves for the El Halcón area were approximately 22.7 MMBoe, of which approximately 30% were classified as proved developed and approximately 70% as proved undeveloped.

Tuscaloosa Marine Shale (TMS)

We have working interests in approximately 169,000 net acres as of December 31, 2013 prospective for the Tuscaloosa Marine Shale. In addition, we had another 136,000 net acres under contract as of December 31, 2013, bringing our total acreage closed and under contract to approximately 305,000, 77% of which is located in Southwest Mississippi and the Louisiana Florida Parishes. Expectations are to spud the next operated well in March 2014 in Wilkinson County, Mississippi. We also expect to participate in several non-operated wells in 2014. As of December 31, 2013, we had no proved reserves associated with the TMS. In addition, we are evaluating joint venture and other similar financing alternatives for our entire TMS position and we are currently engaged in ongoing discussions with several potential partners.

Non-core Areas

Utica / Point Pleasant Formations

We are focused on what we believe to be the volatile oil and liquids-rich gas window in the Utica / Point Pleasant formations, and as of December 31, 2013, we had approximately 140,000 net acres leased or under contract in Trumbull and Mahoning Counties, Ohio, and Mercer, Venango and Crawford Counties, Pennsylvania. Substantially all of our acreage in these areas is either held by shallow production or provides for five years to drill a well plus a renewal option for an additional five years. We continue to evaluate our acreage through drilling and are currently focusing our efforts in the Trumbull and Mahoning counties of Ohio based on well results to date. We are in the process of drilling and completing two new wells with 100% slick water frac designs and plan to flow test these wells by the end of the first quarter of 2014 and the results from these two wells are expected to determine future drilling plans in the play. We expect to gain drilling efficiencies while lowering well costs through the use of pad drilling as a sufficient backlog of approved drilling permits are established. Due to infrastructure requirements, combined with the practice of shutting in wells for up to 45 days after completion in an effort to maximize recoveries, we estimate a spud-to-production time of 120 days per well. Currently, 6 wells are producing, 1 well is being tested, 1 well is resting and 3 wells are waiting on pipeline/market evaluations. Our average daily net production from this area for the three months ended December 31, 2013 was 328 Boe/d. As of December 31, 2013, estimated proved reserves for the Utica / Point Pleasant formations were approximately 0.1 MMBoe, of which 100% were classified as proved developed. We can provide no assurance that this exploratory area, or any wells we subsequently drill in these formations we have targeted for exploration and development, will be successful.

Woodbine Formation

We have working interests in approximately 199,000 net acres as of December 31, 2013 prospective for the Woodbine formation, located in Leon, Madison, Grimes, Walker and Polk Counties, Texas. We currently operate 86% of this production and our working interests range from 4% to 100%. As of December 31, 2013, we had approximately 55 horizontal and 14 vertical operated wells producing in this area. For the three months ended December 31, 2013, our average daily net production was 3,861 Boe/d. Estimated proved reserves for the Woodbine formation totaled 16.3 MMBoe as of December 31, 2013, of which 39% were classified as proved developed and approximately 61% as proved undeveloped.

Other Non-core Areas

We have various other oil and natural gas properties with varying working interests located across the United States, including, the Austin Chalk Trend in East Texas, the Mississippi Lime in Northern Oklahoma and the Midway/Navarro in Southeast Texas. Production from our other non-core areas, including any production from properties divested during the period, totaled approximately 437 MBoe, or 4,760 Boe/d, for the three months ended December 31, 2013. As of December 31, 2013, estimated proved reserves for these other properties were approximately 6.3 MMBoe in aggregate, of which approximately 82% were classified as proved developed and approximately 18% as proved undeveloped. We will consider divesting certain of these assets over time and reinvesting the proceeds in our core resource plays.

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Liquids-Rich Exploratory Plays

In addition to the disclosed areas, we may acquire acreage in other unconventional exploratory plays as opportunities arise. Our strategy for our exploratory projects is to use our in-house geologic and engineering expertise to identify underdeveloped areas that we believe are prospective for oil or liquids-rich production. We can provide no assurance that any of these exploratory areas, or any wells we subsequently drill in the formations we have targeted for exploration and development, will be successful. Due to competitive concerns, we intend to keep the details of such plays confidential until such time as it is appropriate to disclose specifics.

Risk Management

We have designed a risk management policy for the use of derivative instruments to provide partial protection against certain risks relating to our ongoing business operations, such as commodity price declines and interest rate increases. Derivative contracts are utilized to economically hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales on future oil and natural gas production. We hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 18 to 36 months. Historically, we have also entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on our Senior Credit Agreement) to fixed interest rates. We do not enter into derivative contracts for speculative trading purposes.

Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While there are many different types of derivatives available, we typically use costless collar agreements, swap agreements and put options to attempt to manage price risk more effectively. The costless collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All costless collar agreements provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor. The swap agreements call for payments to, or receipts from, counterparties depending on whether the market price of oil and natural gas for the period is greater or less than the fixed price established for that period when the swap agreement is put in place. Under put option agreements, we pay a fixed premium to lock in a specified floor price. If the index price falls below the floor price, the counterparty pays us the difference between the index price and the floor price (netted against the fixed premium payable to the counterparty). If the index price rises above floor price, we pay the fixed premium.

It is our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender or an affiliate of a lender in our Senior Credit Agreement. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* and Item 8. *Consolidated Financial Statements and Supplementary Data* Note 8*, "Derivative and Hedging Activities"* for additional information.

Oil and Natural Gas Operations

Our principal properties consist of leasehold interests in developed and undeveloped oil and natural gas properties and the reserves associated with these properties. Generally, oil and natural gas leases remain in force as long as production in paying quantities is maintained. Leases on undeveloped oil and natural gas properties are typically for a primary term of three to five years within which we are generally required to develop the property or the lease will expire. In some cases, the primary term of leases on our undeveloped properties can be extended by option payments; the amount of any payments and time extended vary by lease.

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The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive[(1)]	10	6.8	1	0.9	6	6.0
Dry	2	2.0	2	2.0	4	4.0
Total Exploratory	12	8.8	3	2.9	10	10.0
Extension Wells:						
Productive[(1)]	203	56.0	101	30.1		
Dry	1	1.0	1	0.9		
Total Extension	204	57.0	102	31.0		
Development Wells:						
Productive[(1)]	68	41.6	87	54.3	43	38.8
Dry					1	0.2
Total Development	68	41.6	87	54.3	44	39.0
Total Wells:						
Productive[(1)]	281	104.4	189	85.3	49	44.8
Dry	3	3.0	3	2.9	5	4.2
Total	284	107.4	192	88.2	54	49.0

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly extension or exploratory wells where there is no production history.

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying provisions. The following table presents a summary of our acreage interests as of December 31, 2013:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
State	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Louisiana	960	960	137,231	133,394	138,191	134,354
Mississippi			65,638	33,944	65,638	33,944
Montana	16,242	8,404	10,419	4,284	26,661	12,688
North Dakota	261,948	109,055	110,493	27,398	372,441	136,453
Ohio	316	316	44,825	44,211	45,141	44,527
Oklahoma	2,080	2,080	11,200	10,720	13,280	12,800
Pennsylvania	748	685	100,637	97,839	101,385	98,524
Texas	281,596	166,465	328,707	211,109	610,303	377,574
Total Acreage	563,890	287,965	809,150	562,899	1,373,040	850,864

The table below reflects the percentage of our total net undeveloped and mineral acreage as of December 31, 2013 that will expire each year if we do not establish production in paying quantities on

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the units in which such acreage is included or do not pay (to the extent we have the contractual right to pay) delay rentals or obtain other extensions to maintain the lease.

Year	Percentage Expiration
2014	12%
2015	36%
2016	21%
2017	27%
2018	3%
2019 & beyond	1%
	100%

For our proved undeveloped locations that are not scheduled to be drilled until after lease expiration, we continually review our near-term lease expirations, actively pursue lease extensions and renewals and modify our drilling schedules in order to preserve the leases.

At December 31, 2013, we had estimated proved reserves of approximately 136 MMBoe comprised of 114.5 MMBbls of crude oil, 9.8 MMBbls of natural gas liquids, and 69.7 Bcf of natural gas. The following table sets forth, at December 31, 2013, these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Oil (MBbls)	44,113	70,397	114,510
Natural Gas Liquids (MBbls)	4,206	5,626	9,832
Natural Gas (MMcf)[(1)]	37,714	32,034	69,748
Equivalent (MBoe)	54,605	81,362	135,967

(1) Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

At December 31, 2013, our estimated proved undeveloped reserves were approximately 81.4 MMBoe, a 24 MMBoe net increase over the previous year's estimate of 57.4 MMBoe. The following table details the changes in proved undeveloped reserves for 2013 (in MBoe):

Beginning proved undeveloped reserves at December 31, 2012	57,386
Undeveloped reserves transferred to developed	(12,901)
Revisions	(8,532)
Purchases	743
Divestitures	(8,451)
Extension and discoveries	53,117
Ending proved undeveloped reserves at December 31, 2013	81,362

The increase in proved undeveloped reserves was primarily attributable to extensions of approximately 53 MMBoe, which were largely in the Bakken / Three Forks and El Halcón areas, where active drilling resulted in the expansion of proven areas. Approximately 19% of the proved undeveloped reserve extensions are associated with well locations that are more than one offset away from existing producing wells. A minor portion of the increase in proved undeveloped reserves of approximately 1 MMBoe was associated with several minor property acquisitions in the Bakken / Three Forks and El Halcón areas.

Partially offsetting the increase in proved undeveloped reserves were decreases due to transfers, divestitures, and technical revisions. Reserve transfers of approximately 13 MMBoe were associated

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with drilling of PUD locations in the Bakken / Three Forks, Woodbine and El Halcón areas. Divestitures of undeveloped reserves of approximately 8 MMBoe relate to several non-core property sales completed during the second half of 2013. Downward revisions of approximately 9 MMBoe were largely in the Halliday field of the Woodbine area, where 2013 development drilling results led to the removal of PUD locations in the lower quality perimeter of the field and a reduction in EUR for the remaining PUD locations.

As of December 31, 2013, all of our proved undeveloped reserves are planned to be developed within five years from the date they were initially recorded. During 2013, approximately $749.0 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

Reliable technologies were used to determine areas where PUD locations are more than one offset away from a producing well. These technologies include seismic data, wire line open hole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic estimated ultimate recoveries from individual producing wells. Our management team has been a leader in data gathering and evaluation in these areas and was instrumental in developing consortiums that allow various operators to exchange data. We relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves.

The estimates of quantities of proved reserves contained in this report were made in accordance with the definitions contained in SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. For additional information on our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data "Supplementary Oil and Gas Information (Unaudited)."*

We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations. Accordingly, all costs incurred in the acquisition, exploration, and development of proved and unproved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, direct internal costs and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. Our net book value of oil and natural gas properties at September 30, 2013 and December 31, 2013 exceeded the ceiling amount. We recorded a full cost ceiling test impairment before income taxes of $1.1 billion ($727.2 million after taxes) for the year ended December 31, 2013. The combined impact of less favorable oil price differentials adversely affecting proved reserve values and the non-routine transfers of unevaluated Woodbine and Utica / Point Pleasant properties to the full cost pool primarily contributed to our ceiling impairment. See further discussion in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 5,*"Oil and Natural Gas Properties."*

Capitalized costs of our evaluated and unevaluated properties at December 31, 2013, 2012 and 2011 are summarized as follows:

	December 31, 2013	December 31, 2012	December 31, 2011
	(In thousands)		
Oil and natural gas properties (full cost method):			
Evaluated	$ 4,960,467	$ 2,669,245	$ 715,666
Unevaluated	2,028,044	2,326,598	
Gross oil and natural gas properties	6,988,511	4,995,843	715,666
Less accumulated depletion	(2,189,515)	(588,207)	(501,993)
Net oil and natural gas properties	$ 4,798,996	$ 4,407,636	$ 213,673

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The following table summarizes our oil, natural gas and natural gas liquids production volumes, average sales price per unit and average costs per unit. In addition, this table summarizes our production for each field that contains 15% or more of our total proved reserves:

	Years Ended December 31,		
	2013	**2012**	**2011**
Production:			
Crude oil MBbl			
Bakken / Three Forks	6,232	650	
Woodbine	1,171	372	
El Halcón	1,194	2	
Electra/Burkburnett	328	437	441
La Copita	10	16	24
Other	1,213	938	419
Total	10,148	2,415	884
Natural Gas MMcf			
Bakken / Three Forks	1,615	224	
Woodbine	506	129	
El Halcón	282	1	
Electra/Burkburnett			
La Copita	508	914	1,079
Other	5,092	3,286	1,583
Total	8,003	4,554	2,662
Natural gas liquids MBbl			
Bakken / Three Forks	227	13	
Woodbine	87	26	
El Halcón	92		
Electra/Burkburnett	34	47	44
La Copita	39	60	83
Other	204	122	49
Total	683	268	176
Production:			
Total MBoe(1)	12,165	3,442	1,504
Average daily production Boe(1)	33,329	9,404	4,121
Average price per unit:(2)			
Crude oil price Bbl	$ 93.08	$ 92.36	$ 93.86
Natural gas price Mcf	3.41	2.80	4.11

Natural gas liquids price Bbl	35.96	41.72	59.69
Barrel of oil equivalent price Boe[1]	81.91	71.75	69.42
Average cost per Boe:			
Production:			
Lease operating	$ 11.44	$ 14.49	$ 19.98
Workover and other	0.52	1.29	1.31
Taxes other than income	7.28	5.59	4.80
Gathering and other	0.97	0.13	0.59

(1)

Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2)

Amounts exclude the impact of cash paid or received on settled commodities derivative contracts as we did not elect to apply hedge accounting.

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The average crude oil and natural gas sales prices above do not reflect the impact of cash paid on, or cash received from, settled derivative contracts as these amounts are reflected as "*Net gain (loss) on derivative contracts*" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact 2013, 2012 and 2011 average crude oil sales prices were $90.66, $93.25 and $91.84 per Bbl and average natural gas sales prices were $3.66, $3.62 and $4.95 per Mcf, respectively.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Markets and Major Customers

The purchasers of our oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, we have not experienced any significant losses from uncollectible accounts. In 2013, four individual purchasers of our production, Shell Trading US Co. (STUSCO), Sunoco Partners Marketing & Terminals, L.P. (Sunoco), Arrow Field Services LLC and Suncor Energy Marketing Inc., each accounted for more than 10% of our total sales, collectively representing 63% of our total sales for the year.

In 2012, two individual purchasers of our production, STUSCO and Sunoco, each accounted for approximately 20% and 19%, respectively, of our total sales. In 2011, STUSCO accounted for $70.4 million, or 68%, of our oil and natural gas revenue for the year.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human

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error and other events may cause accidental leakage or spills of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our operating results, financial position or cash flows. For further discussion on risks see Item 1A. *Risk Factors*.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form spacing units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before permitting oil and natural gas exploration and production to proceed.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws,

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which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically regulate the permitting, construction and operating of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

New programs and changes in existing programs, however, may address various aspects of our business including natural occurring radioactive materials, oil and natural gas exploration and production, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, generally does not regulate most wastes generated by the exploration and production of oil and natural gas. Periodically, however, there are proposals to lift the existing exemption for oil and gas wastes and reclassify them as hazardous wastes. If such proposals were to be enacted, they could have a significant impact on our operating costs and on these of all the industry in general. In the ordinary course of our operations moreover, some wastes generated in connection with our exploration and production activities may be regulated as solid waste under RCRA, as hazardous waste under existing RCRA regulations or as hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate these materials or wastes.

Water Discharges

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff and, as part of our overall evaluation of our current operations, are upgrading storm water management practices at some facilities. We believe that we will be able to obtain, or be included under, these permits, where necessary, and make minor modifications to existing facilities and operations that would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

The federal Safe Drinking Water Act (SDWA), the Underground Injection Control (UIC) regulations promulgated under the SDWA and related state programs regulate the drilling and operation of salt water disposal wells. EPA directly administers the UIC program in some states, and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing.

Our completion operations are subject to regulation, which may increase in the short- or long-term. The well completion technique known as hydraulic fracturing is used to stimulate production of natural gas and oil has come under increased scrutiny by the environmental community, and local, state and federal jurisdictions. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with substantially all of the wells for which we are the operator.

Under the direction of Congress, the EPA has undertaken a study of the effect of hydraulic fracturing on drinking water and groundwater. The EPA has also announced its plan to propose pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations. Congress may consider legislation to amend the Federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Certain states, including Colorado, Utah and Wyoming, have issued similar disclosure rules. Several environmental groups have also petitioned the EPA to extend toxic release reporting requirements under the Emergency Planning Community Right-to-Know Act to the oil and gas extraction industry. Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

In addition, the Department of the Interior has proposed expanded or new regulations concerning the use of hydraulic fracturing on lands under its jurisdiction, which includes lands on which we conduct or plan to conduct operations. A number of other jurisdictions have sought to impose restrictions or bans on hydraulic fracturing. On December 19, 2013, the Pennsylvania Supreme Court overturned several portions of Pennsylvania's law regulating hydraulic fracturing, allowing local governments in Pennsylvania to regulate hydraulic fracturing through local land use regulations. Other local jurisdictions, including Dallas, Texas and several cities in Colorado have adopted regulations restricting hydraulic fracturing. The proliferation of regulations may limit our ability to operate.

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Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

Climate Change

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including those comprising the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories, emissions targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting which went into effect September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. Recently, the EPA issued four new regulations for the oil and natural gas industry, including: a new source performance standard for volatile organic compounds (VOCs); a new source performance standard for sulfur dioxide; an air toxics standard for oil and natural gas production; and an air toxics standard for natural gas transmission and storage. The final rule includes the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several sources, such as storage tanks and other equipment, and limits methane emissions from these sources. Compliance with these regulations will impose additional requirements and costs on our operations.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and reduce demand for our products.

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The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat, or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communications and community right to know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act, commonly referred to as OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public.

Employees and Principal Office

As of December 31, 2013, we had 420 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

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As of December 31, 2013, we leased corporate office space in Houston, Texas at 1000 Louisiana Street, where our principal offices are located. We also lease corporate offices in Tulsa, Oklahoma and Denver, Colorado as well as a number of other field office locations.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Forms 3, 4 and 5 filed on behalf of directors and officers, and any amendments to such reports, available free of charge through our corporate website at *www.halconresources.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our insider trading policy, regulation FD policy, equity-based incentive grant policy, corporate governance guidelines, code of conduct, code of ethics, audit committee charter, compensation committee charter, nominating and corporate governance committee charter and reserves committee charter are available on our website under the heading "Investor Relations Corporate Governance". Within the time period required by the SEC and the New York Stock Exchange (NYSE), as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our Chief Executive Officer and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. You may also read and copy any document we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC's website at *www.sec.gov*. Unless specifically incorporated by reference in this Annual Report on Form 10-K, information that you may find on our website is not part of this report.

ITEM 1A. RISK FACTORS

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs, primarily as a result of our drilling program. We intend to continue to selectively increase our acreage position, which would require capital in addition to the capital necessary to drill on our existing acreage. In addition, it is likely that we will acquire acreage in other areas that we believe are prospective for oil and natural gas production and expend capital to develop such acreage. We expect to use borrowings under our Senior Credit Agreement, proceeds from additional potential non-core asset dispositions and proceeds from potential future capital markets transactions, if necessary, to fund capital expenditures that are in excess of our cash flow and cash on hand.

Our Senior Credit Agreement limits our borrowings to the lesser of the borrowing base and the total commitments. As of December 31, 2013, our Senior Credit Agreement was a $1.5 billion facility with a borrowing base of $700.0 million. As of December 31, 2013, we had no borrowings outstanding, $1.2 million letters of credit outstanding and $698.8 million of borrowing capacity, of which approximately $629 million was available to us under the indebtedness limitation in our indentures. Our borrowing base is determined semi-annually, and may also be redetermined periodically at the discretion of the banks. Lower oil and natural gas prices may result in a reduction in our borrowing base at the next redetermination. A reduction in our borrowing base could require us to repay any indebtedness in excess of the borrowing base. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test applies to all indebtedness and requires that, after giving effect to the incurrence of additional debt, our fixed charge coverage ratio (which is the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters) will be at least 2.0 to 1.0. The second test applies only to borrowings under our credit

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agreements, including indentures and our Senior Credit Agreement that do not meet the first test and it limits these borrowings to the greater of a fixed sum of $750 million and 30% of our adjusted consolidated net tangible assets (or ACNTA, as defined in our indentures), which is determined primarily by the value of discounted future net revenues from proved oil and natural gas reserves. Currently, we are permitted to incur additional indebtedness under these incurrence tests, but may be limited in the future. Lower oil and natural gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

As of December 31, 2013, the restrictive covenants under our indentures limited our incurrence of indebtedness, including all amounts then outstanding under our Senior Credit Agreement, to approximately $629 million. These limitations will continue unless we increase our fixed charge coverage ratio (as defined in the indentures) above the minimum specified level or grow our reserve and asset base. Accordingly, in the near term, we will be required to manage our capital expenditures within this limit, which may require us to defer or delay some of our planned expenditures. As a result of these covenants, in the near term we do not expect to be able to borrow the full amount of our borrowing base under our Senior Credit Agreement.

On October 31, 2013, we entered into the Sixth Amendment to our Senior Credit Agreement. Among other things, the sixth amendment provides for EBITDA to be annualized for the next three fiscal quarters for purposes of measuring compliance with the interest coverage test. Specifically, for the fiscal quarter ended December 31, 2013, the interest coverage test was calculated by utilizing EBITDA for the three month period then ended multiplied by 4; for the fiscal quarter ended March 31, 2014, it will be calculated by utilizing EBITDA for the six month period then ended multiplied by 2; and for the fiscal quarter ended June 30, 2014, it will be calculated by utilizing EBITDA for the nine month period then ended multiplied by 1.333. In the event we have difficulty in meeting these tests or the current ratio test in the future, we would be required to seek additional relief, and there is no assurance that it would be granted.

Additionally, our ability to complete future equity offerings is limited by general market conditions. If we are not able to borrow sufficient amounts under our Senior Credit Agreement and/or are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisition and other activities, which could result in a decrease in our production of oil and natural gas, forfeiture of leasehold interests if we are unable or unwilling to renew them, and could force us to sell some of our assets on an untimely or unfavorable basis, each of which could have a material adverse effect on our results and future operations.

Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we will be able to borrow under our Senior Credit Agreement will be subject to periodic redetermination based in part on current oil and natural gas prices and on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

- the domestic and foreign supply of oil and natural gas;

- the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and maintain oil prices and production levels;

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- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;
- the price and availability of alternative fuels;
- the price of foreign imports;
- worldwide economic conditions; and
- the availability of liquid natural gas imports.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

We are subject to various contractual limitations that affect the discretion of our management in operating our business.

The indentures governing our senior unsecured debt and our Senior Credit Agreement and the certificate of designations governing our convertible preferred stock contain various provisions that may limit our management's discretion in certain respects. In particular, these agreements limit our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase shares of our common stock and, under certain circumstances, our convertible preferred stock, and redeem or repurchase our subordinated debt;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock that is senior to our convertible preferred stock as to dividends or rights upon liquidation, winding-up or dissolution;
- create certain liens;

- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

Additionally, if dividends on our convertible preferred stock are in arrears and unpaid for six or more quarterly periods, the holders (voting as a single class) of our outstanding preferred stock will be entitled to elect two additional directors to our Board of Directors until paid in full.

Compliance with these and other limitations may limit our ability to operate and finance our business and engage in certain transactions in the manner we might otherwise. In addition, if we fail to comply with the limitations under our indentures or Senior Credit Agreement, our creditors, if the

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agreements so provide, may accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us.

Offers or sales of a substantial number of shares of our common stock by our shareholders may cause the market price of our common stock to decline.

In satisfaction of pre-existing contractual obligations, we recently filed with the SEC a shelf registration statement on Form S-3 covering the potential resale by certain selling stockholders of approximately 158.0 million shares of our common stock, and have previously filed similar resale registration statements in lesser amounts for other shareholders. The ability of our shareholders to sell significant numbers of shares of our common stock in the public market pursuant to such registration statements or upon the expiration of lock up agreements or statutory holding periods under Rule 144 of the Securities Act of 1933, as amended, together with any actual sales of our common stock they may choose to make, could cause the market price of our common stock to fall and could make it more difficult for us to raise additional financing through future sales of equity or equity-related securities at a time and price that we deem reasonable or appropriate.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income.

If we were to experience an "ownership change," as determined under section 382 of the Internal Revenue Code, our ability to offset taxable income arising after the ownership change with net operating losses (NOLs) arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate.

We depend on computer and telecommunications systems and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties to our computing and communications infrastructure or our information systems could significantly disrupt our business operations.

We will be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult.

Our business plan contemplates significant acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy, which may include the acquisition of asset packages of producing properties or existing companies or businesses operating in our industry. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and natural gas liquids prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

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The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are generally not able to obtain contractual indemnification for environmental liabilities and normally acquire properties on an "as is" basis.

Significant acquisitions of existing companies or businesses and other strategic transactions may involve additional risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;

- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with our own while carrying on our ongoing business;

- difficulty associated with coordinating geographically separate organizations;

- the challenge of integrating environmental compliance systems to meet requirements of rapidly changing regulations;

- the challenge of attracting and retaining personnel associated with acquired operations; and

- failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within our expected time frame.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to manage the integration process effectively, or if any significant business activities are interrupted as a result of the integration process, our business could be materially and adversely affected.

Assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our recent growth is due significantly to acquisitions of exploration and production companies, producing properties and undeveloped and unevaluated leaseholds. We expect acquisitions may also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating and capital costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

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We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have incurred substantial debt amounting to approximately $3.2 billion as of December 31, 2013. As a result of our indebtedness, we will need to use a substantial portion of our cash flow to pay interest, which will reduce the amount we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our Senior Credit Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have hedging arrangements that are effective in mitigating interest rate fluctuations. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indentures governing our outstanding senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute "indebtedness" as defined under the indentures. At December 31, 2013, our Senior Credit Agreement was a $1.5 billion facility with a borrowing base of $700.0 million. As of December 31, 2013, we had no borrowings outstanding, $1.2 million of letters of credit outstanding and $698.8 million of borrowing capacity, of which approximately $629 million was available to us under the indebtedness limitation in our indentures.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional shares of common stock on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

At December 31, 2013, our corporate credit rating was "B" with a stable outlook by Standard and Poor's (S&P) and "B3" with a stable outlook by Moody's Investors Service (Moody's). Although we are not aware of any current plans of these or other rating agencies to lower their respective ratings on us or our senior debt, we cannot be assured that our credit ratings will not be downgraded. A downgrade in our credit ratings could negatively impact our cost of capital and our ability to effectively execute aspects of our strategy. If our credit rating were downgraded, it could be difficult for us to raise debt in the public debt markets and the cost of that new debt could be higher than debt we could raise with our current ratings. In addition, a downgrade could impact requirements for us to provide financial assurance of performance under contractual arrangements or derivative agreements.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Future deterioration in commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

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Part of our strategy involves drilling in shale formations, some of which are new and emerging, using horizontal drilling and completion techniques. The results of our drilling program using these techniques may be subject to more uncertainties than conventional drilling programs, especially in areas that are new and emerging. These uncertainties could result in an inability to meet our expectations for reserves and production.

The results of our drilling in new or emerging formations, such as the Utica / Point Pleasant formations, Bakken / Three Forks formations, Tuscaloosa Marine Shale formation and the El Halcón area are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and consequently we are less able to predict drilling results in these areas. In addition, the use of horizontal drilling and completion techniques used in all of our shale formations involve certain risks and complexities that do not exist in conventional wells. The ultimate success of our drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

If our drilling results are less than anticipated our investment in these areas may not be as attractive as we anticipate and we could incur material write downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2013, we owned leasehold interests in approximately 149,000 net acres in areas we believe are prospective for the Bakken / Three Forks formations, approximately 94,000 net acres in areas we believe are prospective for the El Halcón area, approximately 169,000 net acres in areas we believe are prospective for the Tuscaloosa Marine Shale formation and 140,000 net acres in areas we believe are prospective for the Utica / Point Pleasant formations. A large portion of our acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of our acreage is located in sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and are therefore subject to additional risk of expirations.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems available in our operating areas, it will be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks to transport our production, which is more expensive and less efficient than transportation via pipeline. Currently, we anticipate that additional pipeline capacity will be required in the Bakken / Three Forks formations and the El Halcón area to transport oil and condensate production, which increased substantially during 2012 and 2013 and is expected to continue to increase. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions and the availability and cost of capital. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently project, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2013, approximately 60% of our estimated reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations, however, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

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We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our business is highly competitive.

The oil and natural gas industry is highly competitive in many respects, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

Our oil and natural gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

- human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- environmental regulations and requirements;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment;
- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce;

- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

As a result of these risks, expenditures, quantities and rates of production, revenues and operating costs may be materially adversely affected and may differ materially from those anticipated by us.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

water discharge and disposal permits for drilling operations;

drilling bonds;

drilling permits;

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- reports concerning operations;
- air quality, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- pipeline construction;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of operations and subject us to liabilities under administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws or the enforcement thereof could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations. Under these laws and other environmental health and safety laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages including the assessment of natural resource damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Some laws and regulations may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation by oil and natural gas-producing states relating to conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

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

From time to time, legislation has been proposed in Congress to amend the federal Safe Drinking Water Act to require federal permitting of hydraulic fracturing and the disclosure of chemicals used in the hydraulic fracturing process. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Federal, state, tribal and local governments have been adopting or considering restrictions on or prohibitions of fracturing are adopted in areas where we currently conduct operations, or in the future plan to conduct operations, we could be subject to additional levels of regulation, operational delays or increased

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operating costs and could have additional regulatory burdens imposed upon us that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

At the Federal level, for example, the EPA is conducting a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2012, the EPA issued a progress report describing its ongoing study, and announcing its expectation that a final draft report will be released for public comment and peer review in 2014. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing, including for example, a federal Bureau of Land Management rulemaking for hydraulic fracturing practices on federal and Indian lands that has resulted in a May 2013 proposal that would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing flowback water from such activities. These activities could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Certain states likewise have adopted, and other states are considering the adoption of, regulations, including Texas and Pennsylvania, where we conduct operations, that impose new or more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing. On December 19, 2013, the Pennsylvania Supreme Court overturned several portions of Pennsylvania's law regulating hydraulic fracturing, allowing local governments in Pennsylvania to regulate hydraulic fracturing through local land use regulations. Other local jurisdictions, including Dallas, Texas and several cities in Colorado have adopted regulations restricting hydraulic fracturing. The proliferation of regulations may limit our ability to operate.

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries, including those comprising the European Union, have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories, emission targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. Recently, the EPA issued four new

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regulations for the oil and natural gas industry, including: a new source performance standard for volatile organic compounds (VOCs); a new source performance standard for sulfur dioxide; an air toxics standard for oil and natural gas production; and an air toxics standard for natural gas transmission and storage. The final rule includes the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several sources, such as storage tanks and other equipment, and limits methane emissions from these sources. Compliance with these regulations will impose additional requirements and costs on our operations.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions or other compliance costs, and reduce demand for our products.

Operations on the Fort Berthold Indian Reservation of the Three Affiliated Tribes in North Dakota are subject to various federal and tribal regulations and laws, any of which may increase our costs and delay our operations.

Various federal agencies within the U.S. Department of the Interior, particularly the Office of Natural Resources Revenue (formerly the Minerals Management Service) and the Bureau of Indian Affairs, along with the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation on which we hold approximately 30,000 net acres. In addition, the Three Affiliated Tribes is a sovereign nation having the right to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands are generally subject to the Native American tribal court system. One or more of these factors may increase our costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on our ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct our operations on such lands.

The ongoing implementation of federal legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production and, periodically, interest expense. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the SEC and the Commodity Futures Trading Commission (or CFTC), along with other federal agencies, to promulgate regulations implementing the new legislation. The CFTC, in coordination with the SEC and various US federal banking regulators, has issued regulations to implement the so-called "Volcker Rule" under which banking entities are generally prohibited from proprietary trading of derivatives. Although conditional exemptions from this general prohibition are available, the Volcker Rule may limit the trading activities of banking entities that have been counterparties to our derivatives trades in the past. Also, a provision of the Dodd-Frank Act known as the "swaps push-out rule" may require some of the banking counterparties to our commodity derivative contracts to "push out" some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

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The CFTC also has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin and position limits; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the Dodd-Frank Act and the CFTC regulations may require compliance with margin requirements and with certain clearing and trade-execution requirements in connection with certain of our derivative activities. Also, the CFTC has re-proposed regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are expected to be made exempt from these limits. It is possible that the CFTC, in conjunction with the US federal banking regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which we would be required to post collateral.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity derivative contracts, and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the implementing regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover claims made against us in the future.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

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

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment, we have entered into certain contracts that extend over several months and or years. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We depend on the skill, ability and decisions of third-party operators of the oil and natural gas properties in which we have a non-operated working interest.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could negatively affect our results of operations.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production, we have entered into oil, natural gas, and natural gas liquids price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil, natural gas and natural gas liquids prices, such transactions may limit our potential gains and increase our potential losses if oil, natural gas and natural gas liquids prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;

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- there is a widening of price differentials between delivery points for our production; or

- the counterparties to our hedging agreements fail to perform under the contracts.

We may be required to take non-cash asset write downs.

We may be required under full cost accounting rules to write down the carrying value of oil and natural gas properties if oil and natural gas prices decline or if there are substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. We utilize the full cost method of accounting for oil and natural gas exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or "ceiling," of the book value of oil and natural gas properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges when hedge accounting is applied, calculated using the unweighted arithmetic average of the first day of each month for the 12-month period ending at the balance sheet date. If the net book value of oil and natural gas properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds the ceiling limitation, SEC regulations require us to impair or "write down" the book value of our oil and natural gas properties.

As of September 30, 2013, the net book value of our oil and natural gas properties exceeded our ceiling amount by $909.1 million, using the WTI unweighted 12-month average price $95.20 per Bbl and the Henry Hub unweighted 12-month average of $3.61 per MMBtu resulting in a write-down of our oil and natural gas properties before income taxes. As of December 31, 2013, the net book value of our oil and natural gas properties exceeded our ceiling amount by $238.7 million using the WTI unweighted 12-month average price $96.94 per Bbl and the Henry Hub unweighted 12-month average of $3.670 per MMBtu resulting in a write-down of our oil and natural gas properties before income taxes. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is impossible to predict the likelihood, timing and magnitude of any future impairments. Depending on the magnitude, a ceiling test write down could negatively affect our results of operations.

Costs associated with unevaluated properties, which were approximately $2.0 billion at December 31, 2013, are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to amortization and the ceiling test limitation.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1. *Business* and is incorporated herein by reference.

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We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 10*, "Commitments and Contingencies,"* and is incorporated herein by reference.

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

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock began trading on the New York Stock Exchange (NYSE) under the symbol HK on March 26, 2012. From February 9, 2012 to March 25, 2012, our common stock traded on the Nasdaq Capital Market under the symbol HK. Prior to February 9, 2012, our common stock traded on the Nasdaq Capital Market under the symbol RAM. The following table sets forth the quarterly high and low sales prices per share of our common stock as reported on the NYSE and Nasdaq Capital Market from January 1, 2012 through December 31, 2013. All share prices reflect a one-for-three reverse stock split, which was effective February 10, 2012.

	High	Low
2013		
First Quarter	$ 8.23	$ 6.36
Second Quarter	7.97	5.13
Third Quarter	6.37	4.43
Fourth Quarter	5.55	3.63
2012		
First Quarter	$ 12.76	$ 8.46
Second Quarter	11.02	8.30
Third Quarter	9.46	6.26
Fourth Quarter	7.34	5.38

We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including our prospects, and such other factors, as the board of directors deems relevant. We are also restricted from paying cash dividends on common stock under our Senior Credit Agreement and under the terms of the indentures governing our other long-term debt.

Approximately 871 registered stockholders of record as of February 24, 2014 held our common stock. In many instances, a stockholder can hold shares through a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to the surrender of our common stock by employees in exchange for the payment of certain tax withholding obligations during the three months ended December 31, 2013.

	Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 2013	14,341	$ 5.42		
November 2013	11,699	4.58		
December 2013	2,903	3.77		

(1) All of the shares were surrendered by employees in exchange for the payment of tax withholding upon the vesting of restricted stock awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our common stock, nor were they considered as or account for as treasury stock.

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Five-Year Stock Performance Graph

The following graph and table compare the cumulative 5-year total return provided to our stockholders on our common stock beginning December 31, 2008 through December 31, 2013, relative to the cumulative total returns of the NYSE Composite Index and the S&P Midcap Oil & Gas Exploration & Production Index. The comparison assumes an investment of $100 (with reinvestment of all dividends at the average of the closing stock prices at the beginning and end of the quarter) was made in our common stock on December 31, 2008, and in each of the indexes, and relative performance is tracked through December 31, 2013. The identity of the companies included in the S&P Midcap Oil & Gas Exploration & Production Index will be provided upon request.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN

Among Halcón Resources Corporation, the NYSE Composite Index,
and the S&P Midcap Oil & Gas Exploration & Production Index

Value of Initial $100 Investment (End of Year)

	Years Ended December 31,					
	2008	**2009**	**2010**	**2011**	**2012**	**2013**
Halcón Resources Corporation	$ 100	$ 233	$ 209	$ 356	$ 262	$ 146
NYSE Composite	100	128	145	140	162	205
S&P Midcap Oil & Gas Exploration & Production index	100	182	274	263	233	371

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ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical financial data derived from our consolidated financial statements. The following data is only a summary and should be read with our historical consolidated financial statements and related notes contained in this document. Refer to Item 1. *Business Recent Developments*, for details regarding recent acquisitions, and business combinations and dispositions that could impact the comparability of the following data.

	Years Ended December 31,				
	2013*(6)*	**2012**	**2011**	**2010**	**2009*(7)***
	(In thousands, except per share data)				
Income Statement Data:					
Total operating revenues	$ 999,506	$ 248,322	$ 104,574	$ 112,621	$ 99,931
Income (loss) from operations	(1,290,947)	(29,717)	19,799	24,526	(44,476)
Net income (loss)	(1,222,662)	(53,885)	(1,403)	2,417	(58,383)
Net income (loss) available to common stockholders	(1,233,407)	(142,330)	(1,403)	2,417	(58,383)
Net income (loss) per share of common stock*(1)*:					
Basic	$ (3.25)	$ (0.91)	$ (0.05)	$ 0.09	$ (2.26)
Diluted	$ (3.25)	$ (0.91)	$ (0.05)	$ 0.09	$ (2.26)

	As of December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
	(In thousands)				
Balance sheet data:					
Working capital deficit	$ (325,756)	$ (390,111)	$ (7,620)	$ (13,878)	$ (15,899)
Total assets	5,356,491	5,041,025	267,174	260,733	306,894
Total long-term debt*(2)(3)*	3,183,823	2,034,498	202,000	196,965	246,041
Preferred stock*(4)*		695,238			
Stockholders' equity (deficit)*(4)(5)*	1,447,610	1,397,982	1,680	(101)	(4,794)

(1) No cash dividends on our common stock were declared or paid for any periods presented.

(2) Excludes current portion of long-term debt for all periods presented.

(3) On December 21, 2011, we entered into a Securities Purchase Agreement with HALRES LLC, formerly Halcón Resources, LLC (HALRES), in which HALRES purchased and we sold 73.3 million shares of our common stock for a purchase price of $275 million and HALRES purchased and we issued a senior convertible promissory note in the principal amount of $275 million, together with five year warrants to purchase 36.7 million shares of our common stock at an exercise price of $4.50 per share, subject to adjustment under certain circumstances. For additional information regarding this recapitalization, see Item 8. *Consolidated Financial Statements and Supplementary Data* Note 2,*"Recapitalization."*

(4) Preferred stock outstanding at December 31, 2012 converted into 108.8 million shares of Halcón common stock on January 18, 2013, following stockholder approval.

(5) On March 5, 2012, we sold in a private placement 4,444.4511 shares of 8% automatically convertible preferred stock (Preferred Stock), par value $0.0001 per share, each share of which automatically converted into 10,000 shares of our common stock on April 17, 2012. We received gross proceeds of approximately $400.0 million, or $9.00 per share of common stock, before offering expenses. No cash dividends were paid on the Preferred Stock as it converted into common stock before May 31, 2012. Refer to Item 8.

Consolidated Financial Statements and

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Supplementary Data Note 11,"*Preferred Stock and Stockholders' Equity,"* for additional information regarding the offering and subsequent conversion.

(6)
For the year ended December 31, 2013, we incurred the following charges which contributed to our net loss for the year, a $1.1 billion full cost ceiling impairment on the carrying value of our oil and natural gas properties, $228.9 million goodwill impairment, and a $67.5 million impairment of other operating property and equipment. Refer to the footnotes included in Item 8. *Consolidated Financial Statements and Supplementary Data*, for additional information regarding these impairments.

(7)
We incurred a $47.6 million impairment on the carrying value of our oil and natural gas properties for the year ended December 31, 2009.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Overview

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural assets in the United States. We were incorporated in Delaware on February 5, 2004 and were recapitalized on February 8, 2012, as described more fully herein. During 2012, we focused our efforts on the acquisition of unevaluated leasehold and producing properties in selected prospect areas, providing us with an extensive drilling inventory in multiple basins that we believe allow for multiple years of production growth and broad flexibility to direct our capital resources to projects with the greatest potential returns. During 2013, we focused on the development of acquired properties and also divested non-core assets in order to fund activities in our core resource plays.

At December 31, 2013, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell), were approximately 136 MMBoe, consisting of 114.5 MMBbls of oil, 9.8 MMBbls of natural gas liquids, and 69.7 Bcf of natural gas. Approximately 40% of our proved reserves were classified as proved developed. We maintain operational control of approximately 92% of our proved reserves. Production for the fourth quarter of 2013 averaged 40,217 Boe/d. Pro forma for the divestitures of certain non-core assets, production for the fourth quarter of 2013 averaged 37,489 Boe/d. Full year 2013 production averaged 33,329 Boe/d compared to 9,404 Boe/d in 2012. Our total operating revenues for 2013 were approximately $999.5 million compared to $248.3 million in 2012.

Our oil and natural gas assets consist of undeveloped acreage positions in unconventional liquids-rich basins/fields. We have acquired acreage and may acquire additional acreage in the Bakken / Three Forks formations in North Dakota, the Eagle Ford formation in East Texas, the Utica / Point Pleasant formations in Ohio and Pennsylvania and the Tuscaloosa Marine Shale formation in Louisiana and Mississippi, as well as several other areas.

Our average daily production increased 254% year over year. The increase in production compared to the prior year period was driven by our operated drilling results and increased production volumes

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associated with the development of properties we acquired in 2012 in the Bakken / Three Forks, Woodbine, and the Eagle Ford formation in East Texas (which we refer to as "El Halcón"). These areas collectively accounted for approximately 25,764 Boe/d in 2013, or 77% of our production. In 2013, we participated in the drilling of 284 gross (107.4 net) wells of which 281 gross (104.4 net) wells were completed and capable of production, and 3 gross (3.0 net) wells were dry holes.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

For the twelve months ended December 31, 2013 we incurred capital expenditures for drilling and completions of approximately $1.5 billion. We expect to spend approximately $950 million on drilling and completion capital expenditures during 2014. Approximately 49% of our 2014 drilling and completions budget is expected to be spent in the Bakken / Three Forks formations in North Dakota, approximately 40% is budgeted for the El Halcón area in East Texas, and the remaining amount is planned for various other project areas, including the Tuscaloosa Marine Shale in Louisiana and Mississippi and the Utica / Point Pleasant formations in Ohio. Our 2014 drilling and completion budget contemplates four to five operated rigs running in the Bakken / Three Forks, three to four operated rigs running in the El Halcón area and one to two operated rigs running in the other areas. Our drilling and completion budget for 2014 is based on our current view of market conditions and current business plans, and is subject to change.

We expect to fund our budgeted 2014 capital expenditures with cash flows from operations, proceeds from additional potential non-core asset divestitures and borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects. In the event our cash flows or proceeds from additional potential non-core asset dispositions are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending.

Recent Developments

Divestitures of Non-core Assets

During the second half of 2013, we entered into three separate purchase and sale agreements with unrelated parties to divest certain non-core assets located throughout the United States for total consideration of approximately $302.0 million, all three of which closed in the fourth quarter of 2013. In aggregate, as of December 31, 2012, estimated proved reserves associated with these non-core assets, were approximately 21.2 MMBoe (69% oil). Production from these non-core assets averaged approximately 4,400 Boe/d during the third quarter of 2013. Proceeds from the sales of the non-core assets were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The borrowing base reduction associated with these non-core assets sales was $50.0 million. Following the closing of the last of these three divestitures on December 20, 2013, the borrowing base on our Senior Credit Agreement was reduced by the $50.0 million to $700.0 million.

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Issuance of Additional 9.75% Senior Notes

On December 19, 2013, we issued an additional $400.0 million aggregate principal amount of our 9.75% senior notes due 2020. The net proceeds from the sale of the additional 2020 Notes of approximately $406.1 million were used to repay a portion of the then outstanding borrowings under our Senior Credit Agreement. In total, we have issued $1.15 billion of 9.75% senior notes due 2020. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Long-Term Debt"* for additional information on the additional 2020 Notes.

Issuance of 9.25% Senior Notes and Common Stock

On August 13, 2013, we issued $400.0 million aggregate principal amount of 9.25% senior notes due 2022 (the 2022 Notes). The net proceeds from the offering were approximately $392.1 million after deducting the commissions and offering expenses and were used to repay a portion of the then outstanding borrowings on our Senior Credit Agreement. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Long-Term Debt"* for additional information on the 2022 Notes.

On August 13, 2013, we also completed the issuance and sale of 43.7 million shares of common stock in an underwritten public offering. The net proceeds from the offering of common stock were approximately $215.2 million, after deducting the underwriting discount and estimated offering expenses. We used the net proceeds from the offering to repay a portion of the then outstanding borrowings on our Senior Credit Agreement. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 11,*"Preferred Stock and Stockholders' Equity"* for additional information on the common stock offering.

Divestiture of Eagle Ford Assets

On July 19, 2013, we completed the sale of our interest in Eagle Ford assets in Fayette and Gonzales Counties, Texas, to private buyers for proceeds of approximately $147.9 million, before post-closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. As of December 31, 2012, we had approximately 3.6 MMBoe of estimated proved reserves associated with these properties. Production from the Eagle Ford assets averaged approximately 1,811 Boe/d during the second quarter of 2013.

Issuance of 5.75% Series A Convertible Perpetual Preferred Stock

On June 18, 2013, we issued in a public offering 345,000 shares of 5.75% Series A Convertible Perpetual Preferred Stock (the Series A Preferred Stock) at a public offering price of $1,000 per share. The net proceeds to us from the offering of the Series A Preferred Stock were approximately $335.5 million, after deducting the underwriting discount and offering expenses. We used the net proceeds from the offering to repay a portion of the then outstanding borrowings under our Senior Credit Agreement. Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, cumulative dividends at the rate of 5.75% per annum on the $1,000 liquidation preference per share of the Series A Preferred Stock, payable quarterly in arrears on each dividend payment date. Dividends may be paid in cash or, where freely transferable by any non-affiliate recipient thereof, in shares of common stock or a combination thereof, and are payable on March 1, June 1, September 1 and December 1 of each year, commencing on September 1, 2013. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 11,*"Preferred Stock and Stockholders' Equity"* for additional information on the Series A Preferred Stock.

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Issuance of Additional 8.875% Senior Notes

On January 14, 2013, we completed the issuance of an additional $600.0 million aggregate principal amount of our 8.875% senior notes due 2021. The additional 2021 Notes were issued at 105% of par and provided net proceeds of approximately $619.5 million (after deducting offering fees). The net proceeds from this offering were used to repay a portion of the then outstanding borrowings under our Senior Credit Agreement and for general corporate purposes. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Long-Term Debt"* for additional information on the additional 2021 Notes.

Amendments to the Senior Credit Agreement and Borrowing Base

On October 31, 2013, we entered into the Sixth Amendment to our Senior Credit Agreement (the Sixth Amendment). The Sixth Amendment increased our borrowing base to $850.0 million, which was subsequently reduced to $700.0 million upon the closing of the final non-core divestiture in December 2013. Additionally, the Sixth Amendment provides for EBITDA (as defined in the Senior Credit Agreement) to be annualized for the next three fiscal quarters for purposes of measuring compliance with the interest coverage test. Specifically, (i) for the fiscal quarter ended December 31, 2013, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the three month period then ended multiplied by 4; (ii) for the fiscal quarter ended March 31, 2014, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the six month period then ended multiplied by 2; and (iii) for the fiscal quarter ended June 30, 2014, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the nine month period then ended multiplied by 1.333.

On June 11, 2013, we entered into the Fifth Amendment to the Senior Credit Agreement which permits us, among other things, to pay cash dividends to holders of our preferred capital stock. On May 8, 2013, we entered into the Fourth Amendment to the Senior Credit Agreement which modified the calculation of the interest coverage test, which was superseded by the Sixth Amendment. On April 26, 2013, we entered into the Third Amendment to our Senior Credit Agreement, which, among other things, provided additional flexibility under certain affirmative and negative covenants and on January 25, 2013, we entered into the Second Amendment to our Senior Credit Agreement which expanded our ability to enter into certain commodity hedging agreements.

Capital Resources and Liquidity

Our near-term capital spending requirements are expected to be funded with cash flows from operations, proceeds from additional potential non-core asset divestitures, proceeds from additional potential capital market transactions and borrowings under our Senior Credit Agreement, which has a current borrowing base of $700.0 million. Our borrowing base is redetermined on a semi-annual basis (with us and the lenders each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations) and adjusted based on the estimated value of our oil and natural gas reserves, the amount and cost of our other indebtedness and other relevant factors. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including redeterminations of our borrowing base, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Our Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0. We are subject to additional covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test, the fixed charge coverage ratio test, applies to all

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indebtedness and requires that after giving effect to the incurrence of additional debt the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.0 to 1.0. The second test allows us to incur additional indebtedness, beyond the limitations of the fixed charge coverage ratio test, as long as this additional debt is incurred under Credit Facilities (as defined in our indentures) and the amount of such additional indebtedness is not more than the greater of a fixed sum of $750 million or 30% of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined primarily by the value of discounted future net revenues from proved oil and natural gas reserves as of the date of such determination. At December 31, 2013, we had no indebtedness outstanding under our Senior Credit Agreement, $1.2 million of letters of credit outstanding and $698.8 million of borrowing capacity, of which approximately $629 million was available to us under the indebtedness limitation in our indentures.

Our ability to meet our debt covenants and our capacity to incur additional indebtedness will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. For example, lower oil and natural gas prices could result in a redetermination of the borrowing base under our Senior Credit Agreement at a lower level and reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets as determined under our Indentures, and thus could reduce our ability to incur indebtedness. Our strategic divestitures of non-core producing properties in favor of investing in undeveloped acreage, coupled with our aggressive drilling plans also impact our near-term ability to comply with our debt covenants, particularly the interest coverage test under our Senior Credit Agreement and the fixed charge coverage ratio under our Indentures by reducing our production and reserves on a current and, for purposes of covenant calculations, a pro forma historical basis, while drilling takes time to replace these losses. Of course, over the longer term, we expect that our strategy and our investments will result in increased production and reserves, lower lease operating costs and more abundant drilling opportunities. As a consequence, we constantly monitor our liquidity and capital resources, endeavor to anticipate potential covenant compliance issues and work with the lenders under our Senior Credit Agreement to address any such issues ahead of time.

As noted above under "Recent Developments", we have in the past obtained amendments to the covenants under our Senior Credit Agreement under circumstances where we anticipated that it might be challenging for us to comply with our financial covenants for a particular period of time. During 2013, we obtained amendments to the calculation of the interest coverage ratio covenant under our Senior Credit Agreement allowing us to annualize our quarterly EBITDA because, among other things, we anticipated that our strategic decision to divest our Eagle Ford shale producing properties and invest in the acquisition and drilling of undeveloped acreage would have caused us to fall below the interest coverage ratio. We have discussed with the administrative agent and various lenders under our Senior Credit Agreement a waiver of compliance with the interest coverage and current ratios for 2014 and expect that request to be granted in conjunction with the next redetermination of our borrowing base prior to the end of our first fiscal quarter. The basis for the waiver request is similar to previously requested waivers described above, i.e., the potential for us to fall out of compliance primarily as a result of our strategic decision to divest producing properties, invest extensively in undeveloped acreage and the long lead times associated with replacing lost production through our drilling program. As part of our plan to manage liquidity risks, we have scaled back our capital expenditures budget, focused our drilling program on our highest return projects, are actively considering various joint venture opportunities to finance development of our Tuscaloosa Marine Shale properties, and continue to explore opportunities to divest non-core properties.

In the event that the lenders under our Senior Credit Agreement prove unwilling to provide us with the covenant flexibility we seek, and we are unable to comply with those covenants, we may be forced to repay or refinance amounts then outstanding under the Senior Credit Agreement and seek alternative sources of capital to fund our business and anticipated capital expenditures. In the event that we are unable to access sufficient capital to fund our business and planned capital expenditures, we may be required to curtail our drilling, development, land acquisition and other activities, which could result in a decrease in our production of oil and natural gas, may be subject to forfeitures of leasehold interests to the extent we are unable or unwilling to renew them, and may be forced to sell some of our assets on an untimely or unfavorable basis, each of which could adversely affect our results of operations and financial condition. Further, the failure to comply with the restrictive covenants relating to our indebtedness could result in the declaration of a default and cross default under the instruments governing our indebtedness, potentially resulting in acceleration of our obligations and adversely impacting our financial condition.

Our future capital resources and liquidity depend, in part, on our success in developing our leasehold interests, growing reserves and production and finding additional reserves. Cash is required to fund capital expenditures necessary to offset inherent declines in our production and proven reserves, which is typical in the capital-intensive oil and natural gas industry. We therefore continuously monitor our liquidity and the capital markets and evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources, acquisition opportunities and drilling success.

We strive to maintain financial flexibility while pursuing our drilling plans and evaluating potential acquisitions, and will therefore likely continue to access capital markets (if on acceptable terms) as necessary to, among other things, maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects while sustaining sufficient operating cash levels. Our ability to complete future debt and equity offerings and maintain or increase our borrowing base is subject to a number of variables, including our level of oil and natural gas production, reserves and commodity prices, as well as various economic and market conditions that have historically affected the oil and natural gas industry. Even if we are otherwise successful in growing our reserves and production, if oil and natural gas prices decline for a sustained period of time, our ability to fund our capital expenditures, complete acquisitions, reduce debt, meet our financial obligations and become profitable may be materially impacted.

Cash Flow

Our primary source of cash in 2013 and 2012 was from financing activities. Our primary source of cash in 2011 was from operating activities. In 2013, proceeds from the 2022 Notes, the additional 2021 Notes, the additional 2020 Notes, the issuance of common stock and the issuance of our Series A Preferred Stock were the primary drivers of the net cash provided by financing activities.

Operating cash flow fluctuations were substantially driven by changes in commodity prices and changes in our production volumes. Working capital was substantially influenced by these variables. Fluctuation in commodity prices and our overall cash flow may result in an increase or decrease in our future capital expenditures. Prices for oil and natural gas have historically been subject to seasonal fluctuations characterized by peak demand and higher prices in the winter heating season; however, the

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impact of other risks and uncertainties have influenced prices throughout recent years. See *Results of Operations* below for a review of the impact of prices and volumes on sales.

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows provided by (used in) operating activities	$ 493,924	$ 84,360	$ 29,835
Cash flows provided by (used in) investing activities	(2,100,699)	(2,832,466)	(25,376)
Cash flows provided by (used in) financing activities	1,607,103	2,750,563	(4,447)
Net increase (decrease) in cash	$ 328	$ 2,457	$ 12

Operating Activities. Net cash flows provided by operating activities were $493.9 million, $84.4 million and $29.8 million for the years ended December 31, 2013, 2012 and 2011, respectively. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs.

Net loss for the year ended December 31, 2013 was $1.2 billion. Non-cash items, including a $1.1 billion full cost ceiling impairment, $228.9 million goodwill impairment, $67.5 million other operating property and equipment impairment and $463.7 million depreciation, depletion and accretion served to more than offset this net loss. The improvement in operating cash flows primarily reflects the impact of the 254% increase in our average daily production compared to the 2012 period, which drove the significant increase in operating revenues.

Net loss for the year ended December 31, 2012 was $53.9 million. Non-cash items, including $90.3 million of depreciation, depletion and accretion, $9.4 million of non-cash interest and amortization and $6.2 million of amortization and write-off of deferred loan costs served to offset this net loss. Our recapitalization, including change in control and related activities which occurred during February 2012, our acquisition of GeoResources, Inc. and transaction costs, and the impact of additional personnel and facilities in support of our expanding business base, drove a significant increase in general and administrative expenditures, which adversely affected our operating cash flows. The remaining improvement in operating cash flows is largely attributable to a favorable mix in working capital changes.

Net cash flows provided by operating activities decreased in 2011 primarily due to a 30% decrease in our production volumes, which was partially offset by a 34% increase in our average realized Boe price compared to the same period in 2010.

Investing Activities. The primary driver of cash used in investing activities is capital spending on our oil and natural gas properties. Net cash used in investing activities was $2.1 billion, $2.8 billion and $25.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

In 2013, we incurred cash expenditures of $2.4 billion on oil and natural gas capital expenditures, of which $1.5 billion related to drilling and completion costs and the remainder was primarily associated with leasing, acquisitions and seismic data. These expenditures were offset by $448.3 million in proceeds received from the sale of our Eagle Ford properties and other non-core asset divestitures. We participated in the drilling of 284 gross (107.4 net) wells of which 281 gross (104.4 net) wells were completed and capable of production and 3 gross (3.0 net) wells were dry holes. We spent an additional $139.3 million on other operating property and equipment capital expenditures primarily related to gathering and transportation systems.

In 2012, we incurred cash expenditures of $579.5 million, net of cash acquired, on our acquisition of GeoResources, Inc., $756.1 million on the acquisition of the Williston Basin Assets, and $296.1 million on our acquisition of the East Texas Assets. Additionally, we spent $1.2 billion on drilling and completion wells, infrastructure projects and other leasehold acquisitions. We participated in the drilling of 192 gross (88.2 net) wells of which 189 gross (85.3 net) wells were completed and capable of production and 3 gross (2.9 net) wells were dry holes. We also drilled and completed 6 gross (5.0 net) salt water disposal wells. We spent an additional $38.5 million on other operating property and equipment capital expenditures primarily related to gathering and transportation systems. Proceeds from sales of oil and natural gas properties were $22.0 million.

In 2011, we spent $25.2 million on capital associated with of evaluated oil and natural properties. We drilled or participated in the drilling of 54 gross (49.0 net) wells on our oil and natural gas properties, of which, 49 gross (44.8 net) wells were successfully completed as producing wells, 5 gross (4.2 net) wells were abandoned wells and 7 gross (5.9 net) wells were either drilling or waiting to be completed at the end of that period.

Financing Activities. Net cash flows provided by financing activities were $1.6 billion and $2.8 billion for the years ended December 31, 2013 and 2012, respectively. Net cash flows used in financing activities were $4.4 million for the year ended December 31, 2011. The primary drivers of cash provided by financing activities are proceeds from the issuance of our senior notes, common stock and preferred stock, offset by repayments under our Senior Credit Agreement.

On December 19, 2013, we issued an additional $400.0 million aggregate principal amount of our 9.75% senior notes due 2020. The net proceeds from the sale of the additional 2020 Notes of approximately $406.1 million were used to repay a portion of the then outstanding borrowings under our Senior Credit Agreement.

On August 13, 2013, we completed the issuance of $400.0 million aggregate principal amount of our 2022 Notes. The net proceeds to us from the offering were approximately $392.1 million after deducting commissions and offering expenses and were used to repay a portion of the then outstanding borrowings under our Senior Credit Agreement.

On August 13, 2013, we also issued of 43.7 million shares of common stock in an underwritten public offering. The net proceeds from the offering of our common stock were approximately $215.2 million, after deducting the underwriting discount and estimated offering expenses. We used the net proceeds from the offering to repay a portion of the then outstanding borrowings on our Senior Credit Agreement.

On June 18, 2013, we issued 345,000 shares of our Series A Preferred Stock in a public offering at a price of $1,000 per share. The net proceeds to us from the offering of the Series A Preferred Stock were approximately $335.5 million, after deducting the underwriting discount and offering expenses. We used the net proceeds from the offering to repay a portion of the then outstanding borrowings under our Senior Credit Agreement.

On January 14, 2013, we issued an additional $600.0 million aggregate principal amount of our 2021 Notes at a price to the initial purchasers of 105% of par. The net proceeds from the sale of the additional 2021 Notes were approximately $619.5 million, after deducting offering fees and expenses. We used the net proceeds from the offering to repay all of the then outstanding borrowings under our Senior Credit Agreement and for general corporate purposes, including funding a portion of our 2013 capital expenditures program.

On December 6, 2012, in conjunction with the closing of the Williston Basin Assets acquisition, we received net proceeds of approximately $294.0 million from the private placement of 41.9 million shares of our common stock with CPP Investment Board PMI-2, Inc., which acquired the shares for a purchase price of approximately $7.16 per share.

On November 6, 2012, we issued $750.0 million aggregate principal amount of our 8.875% senior notes due 2021. Net proceeds of $725.6 million from the offering were placed into escrow pending the acquisition of the Williston Basin Assets and were subsequently released upon closing and used to fund a portion of the cash consideration paid in the acquisition.

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On July 16, 2012, we issued $750.0 million aggregate principal amount of 9.75% senior notes due 2020. Net proceeds of $723.1 million from the offering were placed into escrow pending our acquisition of GeoResources, Inc. and subsequently released from escrow on August 1, 2012 and utilized to fund our acquisition of GeoResources, Inc. and the East Texas Assets.

On March 5, 2012, we issued shares of automatically convertible preferred stock that subsequently converted into approximately 44.4 million shares of common stock for gross proceeds of $400.0 million. We used the proceeds for general corporate purposes.

On February 8, 2012, HALRES LLC recapitalized us with a $550.0 million investment structured as the purchase of $275.0 million in new common stock, a $275.0 million five-year 8.0% convertible note and warrants for the purchase of an additional 36.7 million shares of our common stock at an exercise price of $4.50 per share. The convertible note provided $231.4 million cash flow from borrowings and $43.6 million cash flow from warrants issued. In connection with the closing of the recapitalization, we entered into our Senior Credit Agreement and terminated our prior credit facilities with the payoff of the $210.8 million balance.

Cash flows provided by financing activities include net borrowings under our Senior Credit Agreement of $298.0 million for the year ended December 31, 2012, primarily used to fund our acquisition activities and our ongoing drilling activities.

Contractual Obligations

We have a significant degree of flexibility to adjust the level of our future capital expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, developmental and exploration activities, oil and natural gas price conditions, our access to capital and liquidity and other related economic factors. We currently have no material off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities. The following table summarizes our contractual obligations and commitments by payment periods as of December 31, 2013.

	Payments Due by Period				
Contractual Obligations	**Total**	**2014**	**2015 - 2016**	**2017 - 2018**	**2019 and Beyond**
			(In thousands)		
Senior revolving credit facility	$	$	$	$	$
9.25% senior notes due 2022	400,000				400,000
8.875% senior notes due 2021[(1)]	1,350,000				1,350,000
9.75% senior notes due 2020[(2)]	1,150,000				1,150,000
8.0% convertible note[(3)]	289,669			289,669	
Interest expense on long-term debt[(4)]	1,997,872	294,732	589,464	540,636	573,040
Operating leases	68,631	8,540	17,917	18,346	23,828
Drilling rig commitments	48,947	37,672	11,275		
Other commitments	15,388	15,388			
Total contractual obligations	$ 5,320,507	$ 356,332	$ 618,656	$ 848,651	$ 3,496,868

(1)
Excludes $5.1 million unamortized discount recorded in conjunction with the original issuance of the notes and a $27.5 million premium recorded in conjunction with the January 2013 issuance of the additional 2021 Notes.

(2)
Excludes $8.9 million unamortized discount recorded in conjunction with the original issuance of the notes and a $11.0 million premium recorded in conjunction with the December 2013 issuance of the additional 2020 Notes.

(3)
Excludes $30.3 million unamortized discount recorded in conjunction with the issuance of the note.

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(4) Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2013 less required annual repayments.

We also have various long-term gathering, transportation and sales contracts in the Bakken / Three Forks formations in North Dakota which are not included in the table above. As of December 31, 2013, we had in place nine long-term crude oil contracts and two long-term natural gas contracts in this area. Under the terms of these contracts we have committed a substantial portion of our Bakken / Three Forks production for periods ranging from five to ten years from the date of first production. The sales prices under these contracts are based on posted market rates. We believe that there are sufficient available reserves and supplies in the Bakken / Three Forks formations to meet our commitments, as the proved reserves from this area represent approximately 67% of our total proved reserves.

Additionally, as of December 31, 2013, we had one long-term natural gas transportation contract and one long-term natural gas gathering contract in the Woodbine formation in East Texas which are not included in the table above. The rate under the transportation contract was negotiated based on market rates and the contract term is five years from the date of first production. Under the gathering contract, we have committed substantially all of our natural gas production from specific wells in the area, until a contracted volume amount is reached, in exchange for the construction of a gathering system. The contract term is five years from the date of first production.

Historically, we have been able to meet our delivery commitments.

The contractual obligations table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations. In addition, amounts related to our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total estimated amount of our asset retirement obligations at December 31, 2013 was $39.3 million.

Senior Revolving Credit Facility

In connection with the closing of the Recapitalization, discussed in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 2,*"Recapitalization,"* we entered into a senior secured revolving credit agreement (the Senior Credit Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and the other lenders party thereto on February 8, 2012. The Senior Credit Agreement provides for a $1.5 billion facility with a current borrowing base of $700.0 million. Amounts borrowed under the Senior Credit Agreement will mature on February 8, 2017. The borrowing base will be redetermined semi-annually, with the lenders and us each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the estimated value of our oil and natural gas reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. The borrowing base is subject to a reduction equal to the product of 0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any future notes or other long-term debt securities that we may issue. Funds advanced under the Senior Credit Agreement may be paid down and re-borrowed during the five-year term of the revolver. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 0.50% to 1.50% for ABR-based loans or at specified margins over LIBOR of 1.50% to 2.50% for Eurodollar-based loans. These margins fluctuate based on our utilization of the facility. Advances under the Senior Credit Agreement are secured by liens on substantially all of our properties and assets. The Senior Credit Agreement contains customary representations, warranties and covenants including, among others, restrictions on the payment of dividends on our capital stock and financial covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0.

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At December 31, 2013, we had no indebtedness outstanding under our Senior Credit Agreement, $1.2 million of letters of credit outstanding and $698.8 million of borrowing capacity, of which approximately $629 million was available for us under the indebtedness limitation in our indentures.

Amendments to the Senior Credit Agreement and Borrowing Base

On October 31, 2013, we entered into the Sixth Amendment to our Senior Credit Agreement (the Sixth Amendment). The Sixth Amendment increased our borrowing base to $850.0 million, which was subsequently reduced to $700.0 million upon the closing of the final non-core divestiture in December 2013. Additionally, the Sixth Amendment provides for EBITDA (as defined in the Senior Credit Agreement) to be annualized for the next three fiscal quarters for purposes of measuring compliance with the interest coverage test. Specifically, (i) for the fiscal quarter ended December 31, 2013, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the three month period then ended multiplied by 4; (ii) for the fiscal quarter ended March 31, 2014, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the six month period then ended multiplied by 2; and (iii) for the fiscal quarter ended June 30, 2014, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the nine month period then ended multiplied by 1.333.

On June 11, 2013, we entered into the Fifth Amendment to the Senior Credit Agreement which permits us, among other things, to pay cash dividends to holders of our preferred capital stock. On May 8, 2013, we entered into the Fourth Amendment to the Senior Credit Agreement which modified the calculation of the interest coverage test, which was superseded by the Sixth Amendment. On April 26, 2013, we entered into the Third Amendment to our Senior Credit Agreement, which, among other things, provided additional flexibility under certain affirmative and negative covenants and on January 25, 2013, we entered into the Second Amendment to our Senior Credit Agreement which expanded our ability to enter into certain commodity hedging agreements.

March 2011 Credit Facilities

Our March 2011 credit facilities included a $250.0 million revolving credit facility and a $75.0 million second lien term loan facility, replacing the November 2007 facility. SunTrust Bank was the administrative agent for the revolving credit facility, and Guggenheim Corporate Funding, LLC was the administrative agent for the second lien term loan facility. The revolving credit facility allowed for funds advanced to be paid down and re-borrowed during the five-year term of the revolver, and bore interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The second lien term loan facility provided for payments of interest only during its 5.5 year term, and bore interest at LIBOR plus 9.0% with a 2.0% LIBOR floor, or if any period we elected to pay a portion of the interest "in kind," then the interest rate would have been LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid-in-kind by being added to principal. At December 31, 2011, $127.0 million was outstanding under the revolving credit facility and $75.0 million was outstanding under the second lien term loan facility. On February 8, 2012, we paid in full the outstanding balances under the revolving credit facility and the second lien term loan facility and both facilities were terminated, resulting in a $1.5 million charge to interest expense related to an early termination penalty.

9.25% Senior Notes

On August 13, 2013, we issued at par $400.0 million aggregate principal amount of 9.25% senior notes due 2022 (the 2022 Notes). The net proceeds from the offering of approximately $392.1 million (after deducting commissions and offering expenses) were used to repay a portion of the then outstanding borrowings under our Senior Credit Agreement.

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The 2022 Notes bear interest at a rate of 9.25% per annum, payable semi-annually on February 15 and August 15 of each year, beginning on February 15, 2014. The 2022 Notes will mature on February 15, 2022. The 2022 Notes are senior unsecured obligations of ours, rank equally with all of our current and future senior indebtedness and are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by our existing 100% owned subsidiaries. We, the issuer of the 2022 Notes, have no material independent assets or operations apart from the assets and operations of our subsidiaries.

8.875% Senior Notes

On November 6, 2012, we completed a private offering of $750.0 million aggregate principal amount of 8.875% senior notes due 2021, issued at 99.247% of par (the 2021 Notes). The net proceeds from the offering were approximately $725.6 million after deducting the initial purchasers' discounts, commissions and offering expenses and were used to fund a portion of the cash consideration paid in the Williston Basin Assets acquisition. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 4,*"Acquisitions and Divestitures,"* for additional information regarding the Williston Basin Assets acquisition.

On January 14, 2013, we completed the issuance of an additional $600.0 million aggregate principal amount of 2021 Notes, issued at 105% of par. The net proceeds from the sale of the additional 2021 Notes were approximately $619.5 million (after deducting offering fees). The net proceeds from this offering were used to repay all of the outstanding borrowings under our Senior Credit Agreement and for general corporate purposes, including funding a portion of our 2013 capital expenditures program.

The 2021 Notes bear interest at a rate of 8.875% per annum, payable semi-annually on May 15 and November 15 of each year, beginning on May 15, 2013. The Notes will mature on May 15, 2021. In connection with the issuance of the original 2021 Notes, we recorded a discount of approximately $5.7 million to be amortized over the remaining life of the 2021 Notes using the effective interest method. The remaining unamortized discount was $5.1 million at December 31, 2013. In connection with the issuance of the additional 2021 Notes, we recorded a premium of approximately $30.0 million to be amortized over the remaining life of the 2021 Notes using the effective interest method. The remaining unamortized premium was $27.5 million at December 31, 2013. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Long-Term Debt,"* for additional information regarding the 2021 Notes.

9.75% Senior Notes

On July 16, 2012, we completed a private offering of $750.0 million aggregate principal amount of 9.75% senior notes due 2020 issued at 98.646% of par (the 2020 Notes). The net proceeds from the offering were approximately $723.1 million after deducting the initial purchasers' discounts, commissions and offering expenses and were used to fund a portion of the cash consideration paid in the merger with GeoResources, Inc. (the Merger) and the East Texas Assets acquisition. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 4,*"Acquisitions and Divestitures,"* for additional information regarding the Merger and the East Texas Assets acquisition.

On December 19, 2013, we issued an additional $400.0 million aggregate principal amount of the 2020 Notes at a price to the initial purchasers of 102.750% of par. The net proceeds from the sale of the additional 2020 Notes of approximately $406.1 million (after the initial purchasers' premiums, commissions and offering expenses) were used to repay a portion of the then outstanding borrowings under the Senior Credit Agreement and for general corporate purposes. These notes were issued as "additional notes" under the indenture governing the 2020 Notes and under the indenture are treated as a single series with substantially identical terms as the 2020 Notes previously issued.

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The 2020 Notes bear interest at a rate of 9.75% per annum, payable semi-annually on January 15 and July 15 of each year, which began on January 15, 2013. The 2020 Notes will mature on July 15, 2020. In connection with the issuance of the 2020 Notes, we recorded a discount of approximately $10.2 million to be amortized over the remaining life of the 2020 Notes using the effective interest method. The remaining unamortized discount was $8.9 million at December 31, 2013. In connection with the issuance of the additional 2020 Notes, we recorded a premium of approximately $11.0 million to be amortized over the remaining life of the 2020 Notes using the effective interest method. The remaining unamortized premium was $11.0 million at December 31, 2013. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Long-Term Debt,"* for additional information regarding the 2020 Notes.

8.0% Convertible Note

On February 8, 2012, we issued the 8.0% senior note in the principal amount of $275.0 million (the 2017 Note) together with the February 2012 Warrants for an aggregate purchase price of $275.0 million. The 2017 Note bears interest at a rate of 8% per annum, payable quarterly on March 31, June 30, September 30 and December 31 of each year and matures on February 8, 2017. Through the March 31, 2014 interest payment date, we may elect to pay-in-kind, by adding to the principal of the 2017 Note, all or any portion of the interest due on the 2017 Note. We elected to pay the interest in-kind on March 31, June 30 and September 30, 2012, and rolled $3.2 million, $5.7 million and $5.8 million of interest incurred during the first, second and third quarters of 2012, respectively, into the 2017 Note, increasing the principal amount to $289.7 million. We did not elect to pay-in-kind interest for the quarterly payments due subsequently to September 30, 2012. As of February 8, 2014, the note can be converted into common stock. Each $4.50 of principal and accrued but unpaid interest is convertible into one share of our common stock. The 2017 Note is a senior unsecured obligation of ours.

We allocated the proceeds received for the 2017 Note and February 2012 Warrants on a relative fair value basis. Consequently, we recorded a discount of $43.6 million to be amortized over the remaining life of the 2017 Note utilizing the effective interest rate method. The remaining unamortized discount was $30.3 million at December 31, 2013.

Promissory Notes

On December 28, 2012, we completed the acquisition of certain oil and natural gas properties in Brazos County, Texas for approximately $83.7 million, before and subject to, customary closing adjustments, consisting of approximately $8.4 million in cash and approximately $75.3 million in promissory notes. During the three months ended March 31, 2013, we completed our review of the properties and paid approximately $62.4 million during the period for properties deemed to have clear title and no defects. In addition, notice was given to the sellers of our assertion of title and environmental defects amounting to $12.9 million for the remaining properties. During the three months ended September 30, 2013, the title and environmental defects were cured by the sellers and we paid the remaining portion of the purchase price. The promissory notes were classified as current at December 31, 2012.

In conjunction with the issuance of the promissory notes in December 2012, we recorded a discount of approximately $0.6 million to be amortized over the remaining life of the promissory notes using the effective interest method. We expensed the discount during the first quarter of 2013.

Off-Balance Sheet Arrangements

At December 31, 2013, we did not have any material off-balance sheet arrangements.

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Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See *Results of Operations* above and Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using the unweighted arithmetic average of the first day of the month for each of the 12-month prices for oil and natural gas within the period, holding prices and costs constant and applying a 10% discount rate.

Full Cost Method

We use the full cost method of accounting for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized into a cost center (the amortization base or full cost pool). Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. All general and administrative costs unrelated to drilling activities are expensed as incurred. The capitalized costs of our evaluated oil and natural gas properties, plus an estimate of our future development and abandonment costs are amortized on a unit-of-production method based on our estimate of total proved reserves. Our financial position and results of operations could have been significantly different had we used the successful efforts method of accounting for our oil and natural gas activities.

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Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and Securities Exchange Commission (SEC) guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depletion, depreciation and accretion expense and the full cost ceiling test limitation. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under defined economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

Our estimated proved reserves for the years ended December 31, 2013 and 2012 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. Our estimated proved reserves for the year ended December 31, 2011 was prepared by Forrest A. Garb & Associates, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Consolidated Financial Statements and Supplementary Data "*Supplemental Oil and Gas Information (Unaudited).*"

Depreciation, Depletion and Accretion

Our rate of recording depletion, depreciation and accretion expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. At December 31, 2013, a five percent positive revision to proved reserves would decrease the DD&A rate by approximately $1.77 per Boe and a five percent negative revision to proved reserves would increase the DD&A rate by approximately $1.95 per Boe.

Full Cost Ceiling Test Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write down to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write downs of our oil and natural gas properties could occur in the future.

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If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2013 had been 10% lower while all other factors remained constant, our ceiling amount related to our net book value of oil and natural gas properties would have been reduced by approximately $545.0 million. This reduction would have increased our full cost ceiling impairment by approximately $545.0 million before income taxes.

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production facilities, gathering systems and related structures and restoration costs. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing 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 judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. A five percent decrease or increase in future development and abandonment costs would decrease or increase the DD&A rate by approximately $0.78 per Boe at December 31, 2013.

Asset Retirement Obligations

We have obligations to remove tangible equipment and facilities associated with our oil and natural gas wells and our gathering systems, and to restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are associated with plugging and abandoning wells and our gathering systems. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments.

Accounting for Derivative Instruments and Hedging Activities

We account for our derivative activities under the provisions of Accounting Standards Codification (ASC) No. 815, *Derivatives and Hedging* (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, we may hedge a portion of our forecasted oil, natural gas, and natural gas liquids production. Derivative contracts entered into by us have consisted of transactions in which we hedge the variability of cash flow related to a forecasted transaction. We elected to not designate any of our positions for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

Goodwill

We account for goodwill in accordance with ASC 350, *Intangibles Goodwill and Other* (ASC 350). Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350 requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more

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frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. Our goodwill related to the acquisition of GeoResources in 2012.

Accounting Standards Update (ASU) No. 2011-08, *Testing for Goodwill Impairment* (ASU 2011-08), simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying value. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then the entity does not have to perform the two-step impairment test. However, if the same conclusion is not reached, the Company is required to perform the first step of the two-step impairment test. In this step, the fair value of the reporting unit is calculated and compared to the carrying value of the reporting unit. If the carrying value exceeds the fair value, then the entity must perform the second step of the impairment test to measure the amount of impairment loss, if any. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test.

Income Taxes

Our provision for taxes includes both state and federal taxes. We account for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized.

In assessing the need for a valuation allowance on our deferred tax assets, we consider possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies. We consider all available evidence (both positive and negative) in determining whether a valuation allowance is required. A significant item of objective negative evidence considered was the cumulative book loss over the three-year period ended December 31, 2013 driven primarily by the full cost ceiling impairments in 2013. Based upon the evaluation of the available evidence we recorded an increase of $262.8 million to our valuation allowance resulting in $265.1 million being applied against our deferred tax assets as of December 31, 2013.

We follow ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the financial statements. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows. The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

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Comparison of Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

We reported a net loss of $1.2 billion for the year ended December 31, 2013 compared to a net loss of $53.9 million for the comparable period in 2012. The following table summarizes key items of comparison and their related change for the periods indicated.

	Years Ended December 31,		
In thousands (except per unit and per Boe amounts)	**2013**	**2012**	**Change**
Net income (loss)	$ (1,222,662)	$ (53,885)	$ (1,168,777)
Operating revenues:			
Oil	944,535	223,056	721,479
Natural gas	27,319	12,735	14,584
Natural gas liquids	24,564	11,180	13,384
Other	3,088	1,351	1,737
Operating expenses:			
Production:			
Lease operating	139,182	49,859	89,323
Workover and other	6,268	4,429	1,839
Taxes other than income	88,622	19,253	69,369
Gathering and other	11,745	459	11,286
Restructuring	4,471	2,406	2,065
General and administrative:			
General and administrative	115,298	104,608	10,690
Share-based compensation	17,112	6,741	10,371
Depletion, depreciation and accretion:			
Depletion Full cost	453,537	86,215	367,322
Depreciation Other	6,522	1,763	4,759
Accretion expense	3,596	2,306	1,290
Full cost ceiling impairment	1,147,771		1,147,771
Other operating property and equipment impairment	67,454		67,454
Goodwill impairment	228,875		228,875
Other income (expenses):			
Net gain (loss) on derivative contracts	(31,233)	(6,126)	(25,107)
Interest expense and other, net	(58,198)	(31,223)	(26,975)
Income tax benefit (provision)	157,716	13,181	144,535
Production:			
Crude oil MBbls	10,148	2,415	7,733
Natural gas Mmcf	8,003	4,554	3,449
Natural gas liquids MBbls	683	268	415
Total MBoe*(1)*	12,165	3,442	8,723
Average daily production Boe*(1)*	33,329	9,404	23,925
Average price per unit*(2)*:			
Crude oil price Bbl	$ 93.08	$ 92.36	$ 0.72
Natural gas price Mcf	3.41	2.80	0.61
Natural gas liquids price Bbl	35.96	41.72	(5.76)
Total per Boe*(1)*	81.91	71.75	10.16
Average cost per Boe:			
Production:			
Lease operating	$ 11.44	$ 14.49	$ (3.05)
Workover and other	0.52	1.29	(0.77)
Taxes other than income	7.28	5.59	1.69
Gathering and other	0.97	0.13	0.84
Restructuring	0.37	0.70	(0.33)
General and administrative:			
General and administrative	9.48	30.39	(20.91)
Share-based compensation	1.41	1.96	(0.55)
Depletion	37.28	25.05	12.23

(1)

Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

For the year ended December 31, 2013, oil, natural gas and natural gas liquids revenues increased $749.4 million from the same period in 2012. The increase was primarily due to increased production volumes associated with the development of the properties we acquired in 2012 in the Bakken / Three Forks, Woodbine and El Halcón areas. These areas collectively accounted for 8,243 MBoe and $717.8 million of incremental revenues year over year. Realized average prices per Boe increased $10.16 per Boe to $81.91 per Boe.

Lease operating expenses increased $89.3 million for the year ended December 31, 2013, primarily due to $73.4 million of expenses on properties acquired in 2012 and our development of these properties in 2013. Lease operating expenses were $11.44 per Boe in 2013 compared to $14.49 per Boe in 2012. The decrease per Boe is primarily due to lower operating expenses per Boe on the newly developed properties. As we continue to strive for operational efficiencies and divest non-core properties with higher operating costs our lease operating expense per Boe should decline.

Workover and other expenses increased $1.8 million for the year ended December 31, 2013 compared to the same period in 2012 primarily due to $3.2 million of expenses associated with increased activity on acquired properties as we continue to develop these areas.

Taxes other than income increased $69.4 million for the year ended December 31, 2013 as compared to the same period in 2012 primarily due to increased production from the development of the properties we acquired in 2012. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease proportionately. On a per unit basis, taxes other than income were $7.28 per Boe and $5.59 per Boe, for the years ended 2013 and 2012, respectively. The increase on a per Boe basis in 2013 is driven by increased production and revenue in our Bakken / Three Forks area which has higher production tax rates than our other areas.

Gathering and other expenses for the year ended December 31, 2013 and 2012 were $11.7 million and $0.5 million, respectively. In 2013, approximately $3.4 million of these expenses were attributable to midstream infrastructure that we developed in our Woodbine and Utica / Point Pleasant operating areas and approximately $8.3 million relates to gathering and other fees paid on our oil and natural gas production.

In March 2012, we announced our intention to close our Plano, Texas office and began the process of relocating key administrative functions to our corporate headquarters in Houston, Texas (the restructuring). As part of the restructuring, we offered certain severance and retention benefits to affected employees, through May 2013. Approximately $0.5 million of our restructuring expense in 2013 relates to costs from the restructuring. Additionally, in the fourth quarter of 2013, in conjunction with our divestitures of certain non-core assets, we incurred approximately $4.0 million in severance costs and accelerated stock-based compensation expense related to the termination of certain employees in these non-core areas.

General and administrative expense for the year ended December 31, 2013 increased $10.7 million to $115.3 million as compared to the same period in 2012. The increase was primarily due to increases in payroll and related employee benefit costs of $17.9 million and office related expenses of $9.2 million, in support of our expanding employee and business base, partially offset by a decrease in transaction costs. On a per unit basis, general and administrative expenses were $9.48 per Boe and $30.39 per Boe, for the years ended 2013 and 2012, respectively.

Share-based compensation expense for the year ended December 31, 2013 was $17.1 million, an increase of $10.4 million compared to the same period in 2012. In 2012, we incurred approximately $4.3 million for the accelerated vesting of restricted stock awards and stock appreciation rights resulting from the change in control that occurred due to our recapitalization. The year over year increase,

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excluding these change in control payments, is approximately $6.1 million, reflecting our investment in additional personnel since the prior year.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense increased $367.3 million to $453.5 million for the year ended December 31, 2013 compared to the same period in 2012 of $86.2 million, primarily due to a higher depletion rate per Boe and increased production. On a per unit basis, depletion expense was $37.28 per Boe for the year ended December 31, 2013 compared to $25.05 per Boe for the year ended December 31, 2012. The increase in depletion expense and the depletion rate per Boe is primarily due to the increase in production volumes and in our capital spending associated with our development of the properties we acquired in 2012. Additionally, in the third quarter of 2013, we transferred unevaluated property costs of $655.7 million to the full cost pool, which is discussed further below, which contributed to the increase in depletion expense on both an absolute dollar and per Boe basis when compared to 2012.

We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling," based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. We recorded a full cost ceiling test impairment before income taxes of $1.1 billion for the year ended December 31, 2013. During the year ended December 31, 2013, we transferred $655.7 million of unevaluated property costs to the full cost pool primarily related to Woodbine assets in East Texas where capital has been reallocated to El Halcón, and certain Utica / Point Pleasant assets in Northwest Pennsylvania related to non-economical drilling results obtained in the third quarter of 2013. The combined impact of less favorable oil price differentials adversely affecting proved reserve values and the aforementioned non-routine transfers of unevaluated properties to the full cost pool primarily contributed to the ceiling impairment. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

We review our gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360. For the year ended December 31, 2013, we recorded a non-cash impairment charge of $67.5 million. The impairment relates to our gross investments of $72.1 million in gas gathering infrastructure that will not be economically recoverable due to our shift in exploration, drilling and developmental plans from the Woodbine area to El Halcón during the third quarter of 2013.

During the third quarter of 2013, we performed our annual goodwill impairment test, using a measurement date of July 1, and based on this review; we recorded a non-cash impairment charge of $228.9 million to reduce the carrying value of goodwill to zero. In the first step of the goodwill impairment test, we determined that the fair value of our reporting unit was less than the carrying amount, including goodwill, primarily due to pricing deterioration in the NYMEX forward pricing curve for oil, coupled with less favorable oil price differentials in our core areas, both factors which adversely impacted the fair value of our proved reserves. Therefore, we performed the second step of the goodwill impairment test, which led us to conclude that there would be no remaining implied fair value attributable to goodwill.

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Accretion expense is a function of changes in the discounted asset retirement obligation liability from period to period. We recorded $3.6 million for the year ended December 31, 2013, compared to $2.3 million for the year ended December 31, 2012.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2013, we had a $24.8 million derivative asset, $2.0 million of which was classified as current, and we had a $37.2 million derivative liability of which $17.9 million was classified as current. We recorded a net derivative loss of $31.2 million ($10.1 million net unrealized loss and $21.1 million net realized loss on settled contracts and premium costs) for the year ended December 31, 2013 compared to a net derivative loss of $6.1 million ($13.2 million net unrealized loss and $7.1 million net realized gain on settled contracts and premium costs) in the prior year.

Interest expense increased $27.0 million for the year ended December 31, 2013. This increase was primarily due to the issuance of new long-term debt partially offset by capitalized interest expense on unevaluated properties. We incurred interest expense before capitalization of $259.2 million in 2013 compared to $85.4 million in the prior year. Due to significant costs incurred during 2012 on unevaluated properties we began capitalizing interest, resulting in $204.0 million and $53.5 million capitalized for the years ended December 31, 2013 and 2012, respectively.

We recorded an income tax benefit of $157.7 million on a loss before income taxes of $1.4 billion for the year ended December 31, 2013. The benefit reflects the impact of the change in the valuation allowance for the year of $262.8 million and the nondeductible goodwill impairment of $84.5 million. For the year ended December 31, 2012, we recorded an income tax benefit of $13.2 million on a loss before income taxes of $67.1 million. The benefit reflects nondeductible interest expense on the convertible notes issued as part of the Recapitalization of $3.2 million and nondeductible merger related costs of $3.6 million.

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

We reported a net loss of $53.9 million for the year ended December 31, 2012 compared to a net loss of $1.4 million for the comparable period in 2011. The following table summarizes key items of comparison and their related change for the periods indicated.

In thousands (except per unit and per Boe amounts)	Years Ended December 31, 2012	Years Ended December 31, 2011	Change
Net income (loss)	$ (53,885)	$ (1,403)	$ (52,482)
Operating revenues:			
Oil	223,056	82,968	140,088
Natural gas	12,735	10,933	1,802
Natural gas liquids	11,180	10,505	675
Other	1,351	168	1,183
Operating expenses:			
Production:			
Lease operating	49,859	30,043	19,816
Workover and other	4,429	1,967	2,462
Taxes other than income	19,253	7,214	12,039
Gathering and other	459	885	(426)
Restructuring	2,406	1,071	1,335
General and administrative:			
General and administrative	104,608	17,025	87,583
Share-based compensation	6,741	3,584	3,157
Depletion, depreciation and accretion:			
Depletion Full cost	86,215	20,381	65,834
Depreciation Other	1,763	964	799
Accretion expense	2,306	1,641	665
Other income (expenses):			
Net gain (loss) on derivative contracts	(6,126)	3,479	(9,605)
Interest expense and other, net	(31,223)	(17,879)	(13,344)
Income tax benefit (provision)	13,181	(6,802)	19,983
Production:			
Crude oil MBbls	2,415	884	1,531
Natural gas Mmcf	4,554	2,662	1,892
Natural gas liquids MBbls	268	176	92
Total MBoe[(1)]	3,442	1,504	1,938
Average daily production Boe[(1)]	9,404	4,121	5,283
Average price per unit[(2)]:			
Crude oil price Bbl	$ 92.36	$ 93.86	$ (1.50)
Natural gas price Mcf	2.80	4.11	(1.31)
Natural gas liquids price Bbl	41.72	59.69	(17.97)
Total per Boe[(1)]	71.75	69.42	2.33
Average cost per Boe:			
Production:			
Lease operating	14.49	19.98	(5.49)
Workover and other	1.29	1.31	(0.02)
Taxes other than income	5.59	4.80	0.79
Gathering and other	0.13	0.59	(0.46)
Restructuring	0.70	0.71	(0.01)
General and administrative:			
General and administrative	30.39	11.32	19.07
Share-based compensation	1.96	2.38	(0.42)
Depletion	25.05	13.55	11.50

(1) Natural gas reserves are converted to oil reserves using a 1:6 equivalent ratio. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

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For the year ended December 31, 2012, oil, natural gas and natural gas liquids revenues increased $142.6 million from the same period in 2011. The increase was primarily due to an increase in production volumes resulting from the Merger, the East Texas Assets acquisition and the Williston Basin Assets acquisition which collectively accounted for an increase of 1,942 MBoe in production and $145.3 million of incremental revenues. Realized average prices per Boe increased $2.33 per Boe to $71.75 per Boe.

Lease operating expenses increased $19.8 million for the year ended December 31, 2012, primarily due to $16.3 million of costs incurred on our newly acquired assets. The remaining increases are due to surface repair and maintenance costs. Lease operating expenses were $14.49 per Boe in 2012 compared to $19.98 per Boe in 2011. The decrease per Boe is primarily due to a lower rate per Boe on the newly acquired properties.

Workover and other expenses increased $2.5 million for the year ended December 31, 2012 compared to the same period in 2011 primarily due to $2.7 million of expenses incurred on our newly acquired assets.

Taxes other than income increased $12.0 million for the year ended December 31, 2012 as compared to the same period in 2011 primarily due to $9.6 million of production taxes incurred on our newly acquired properties. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. On a per unit basis, taxes other than income were $5.59 per Boe and $4.80 per Boe, for the years ended 2012 and 2011, respectively. The increase on a per Boe basis in 2012 is driven by increased production and revenue in our Bakken / Three Forks area which has higher production tax rates than our other areas.

In March 2012, we announced our intention to close the Plano, Texas office and began the process of relocating key administrative functions to our corporate headquarters in Houston, Texas (the Restructuring). As part of the Restructuring, we offered certain severance and retention benefits to affected employees. We have incurred $2.4 million in Restructuring costs for the year ended December 31, 2012. In October 2011, we announced a company-wide reorganization of our operating and administrative functions. As part of the reorganization, we recognized restructuring expense of $1.1 million, including $0.7 million of one-time severance benefits, $0.2 million of retention payments, and $0.2 million of share-based compensation related to the acceleration of employee restricted stock awards and payment of share appreciation rights. The reorganization was completed in full during the quarter ended December 31, 2011.

General and administrative expense for the year ended December 31, 2012 increased $87.6 million to $104.6 million as compared to the same period in 2011. The increase was primarily due to transaction costs of $41.0 million in the aggregate for the Merger, the East Texas Assets acquisition and the Williston Basin Assets acquisition. We incurred $8.9 million in connection with the Recapitalization, which included $5.4 million for change in control payments and $2.5 million for engagement termination fees. The remaining increase in general and administrative expenses is attributable to increases in payroll and related employee benefit costs of $18.3 million, office related expenses of $5.2 million and professional fees of $9.7 million, in support of the expanding business base and increased corporate activities subsequent to the Recapitalization. On a per unit basis, general and administrative expense was $30.39 per Boe and $11.32 per Boe, for the years ended 2012 and 2011, respectively.

Share-based compensation expense for the year ended December 31, 2012 was $6.7 million, an increase of $3.2 million compared to the same period in 2011. The increase is primarily due to the accelerated vesting of restricted stock awards and stock appreciation rights resulting from the change in control that occurred due to our Recapitalization, which totaled $4.3 million.

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Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense increased $65.8 million to $86.2 million for the year ended December 31, 2012 compared to the same period in 2011 of $20.4 million, primarily due to a higher depletion rate per Boe and increased production. On a per unit basis, depletion expense was $25.05 per Boe for the year ended December 31, 2012 compared to $13.55 per Boe for the year ended December 31, 2011. The increase in depletion and the depletion rate per Boe and production is primarily due to the Merger and acquisitions of the East Texas Assets and the Williston Basin Assets.

Accretion expense is a function of changes in the discounted asset retirement obligation liability from period to period. We recorded $2.3 million for the year ended December 31, 2012, compared to $1.6 million for the year ended December 31, 2011.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. We have also, in the past, entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2012, we had a $7.8 million derivative asset, $7.4 million of which was classified as current, and we had a $12.9 million derivative liability of which $10.4 million was classified as current. We recorded a net derivative loss of $6.1 million ($13.2 million net unrealized loss and $7.1 million net realized gain on settled contracts and premium costs) for the year ended December 31, 2012 compared to a net derivative gain of $3.5 million ($4.8 million net unrealized gain and $1.3 million net realized loss on settled contracts and premium costs) in the prior year.

Interest expense increased $13.3 million for the year ended December 31, 2012. This increase was primarily due to the issuance of new long-term debt partially offset by capitalized interest expense on unevaluated properties. We incurred interest expense before capitalization of $85.4 million in 2012 compared to $17.4 million in the prior year. Due to significant costs incurred during 2012 on unevaluated properties we began capitalizing interest during 2012, resulting in $53.5 million capitalized for the year ended December 31, 2012. No amounts were capitalized in 2011.

We recorded an income tax benefit of $13.2 million on a loss before income taxes of $67.1 million for the year ended December 31, 2012. The benefit reflects nondeductible interest expense on the convertible notes issued as part of the Recapitalization of $3.2 million and nondeductible merger related costs of $3.6 million. For the year ended December 31, 2011, we recorded an income tax provision of $6.8 million on income before income taxes of $5.4 million. The income tax provision for 2011 included a $6.0 million decrease to deferred tax assets, including a Section 382 adjustment related to net operating loss limitations and a decrease in the valuation allowance of $1.9 million.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, "*Summary of Significant Events and Accounting Policies*."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivative Instruments and Hedging Activity

We are exposed to various risks including energy commodity price risk. When oil, natural gas, and natural gas liquids prices decline significantly our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we

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have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include costless collars, swaps, and put options. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 70% to 80% of our current and anticipated production for the next 18 to 36 months. Our hedge policies and objectives may change significantly as our operational profile changes and/or commodities prices change. We do not enter into derivative contracts for speculative trading purposes.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender of an affiliate of a lender in our Senior Credit Agreement. We did not post collateral under any of these contracts as they are secured under our Senior Credit Agreement. Please refer to Item 8. *Consolidated Financial Statements and Supplementary Data* Note 8,*"Derivative and Hedging Activities"* for additional information.

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Historically, we entered into interest rate swaps to reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. At December 31, 2013, we did not have any open positions that converted our variable interest rate debt to fixed interest rates. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging*, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 8,*"Derivative and Hedging Activities"* for more details.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments*, (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 7, "*Fair Value Measurements"* for additional information.

Interest Rate Sensitivity

Historically, we have been exposed to interest rate risk exposure primarily from fluctuations in short-term rates, which are LIBOR and ABR based. These fluctuations can cause reductions of earnings or cash flows due to increases in the interest rates that we have historically paid on these obligations. At December 31, 2013, total debt including related discounts and premiums was $3.2 billion which bears interest at a weighted average fixed interest rate of 9.2% per year. At December 31, 2013, we did not have any amounts drawn under our credit facility. We do not currently have any long-term debt that bears interest at floating and variable interest rates. If we incur future indebtedness which bears interest at variable rates, fluctuations in market interest rates could cause our annual interest costs to fluctuate.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Halcón Resources Corporation (the Company), including the Company's Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company's internal control system was designed to provide reasonable assurance to the Company's Management and Board of Directors regarding the preparation and fair presentation of published 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.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based on this evaluation, management concluded that Halcón Resources Corporation's internal control over financial reporting was effective as of December 31, 2013.

Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2013 which is included herein.

/s/ FLOYD C. WILSON	/s/ MARK J. MIZE
Floyd C. Wilson *Chairman of the Board* *and Chief Executive Officer* Houston, Texas February 27, 2014	Mark J. Mize *Executive Vice President,* *Chief Financial Officer and Treasurer*

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Halcón Resources Corporation
Houston, Texas

We have audited the internal control over financial reporting of Halcón Resources Corporation and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. The Company'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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 and 2012 of the Company and our report dated February 27, 2014 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 27, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Halcón Resources Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of Halcón Resources Corporation and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended. 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. The consolidated financial statements of the Company for the year ended December 31, 2011 were audited by other auditors whose report, dated March 5, 2012, expressed an unqualified opinion on those statements.

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 audits 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, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992 and our report dated February 27, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 27, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Halcón Resources Corporation

We have audited the accompanying consolidated statements of operations, stockholders' deficit and cash flows for the year ended December 31, 2011 of Halcón Resources Corporation (formerly RAM Energy Resources, Inc., a Delaware corporation) and subsidiaries (the "Company"). These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements 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 the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated 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 audit provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Halcón Resources Corporation and subsidiaries for the year ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas
March 5, 2012

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HALCÓN RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31,		
	2013	**2012**	**2011**
Operating revenues:			
Oil, natural gas and natural gas liquids sales:			
Oil	$ 944,535	$ 223,056	$ 82,968
Natural gas	27,319	12,735	10,933
Natural gas liquids	24,564	11,180	10,505
Total oil, natural gas and natural gas liquids sales	996,418	246,971	104,406
Other	3,088	1,351	168
Total operating revenues	999,506	248,322	104,574
Operating expenses:			
Production:			
Lease operating	139,182	49,859	30,043
Workover and other	6,268	4,429	1,967
Taxes other than income	88,622	19,253	7,214
Gathering and other	11,745	459	885
Restructuring	4,471	2,406	1,071
General and administrative	132,410	111,349	20,609
Depletion, depreciation and accretion	463,655	90,284	22,986
Full cost ceiling impairment	1,147,771		
Other operating property and equipment impairment	67,454		
Goodwill impairment	228,875		
Total operating expenses	2,290,453	278,039	84,775
Income (loss) from operations	(1,290,947)	(29,717)	19,799
Other income (expenses):			
Net gain (loss) on derivative contracts	(31,233)	(6,126)	3,479
Interest expense and other, net	(58,198)	(31,223)	(17,879)
Total other income (expenses)	(89,431)	(37,349)	(14,400)
Income (loss) before income taxes	(1,380,378)	(67,066)	5,399
Income tax benefit (provision)	157,716	13,181	(6,802)
Net income (loss)	(1,222,662)	(53,885)	(1,403)

Non-cash preferred dividend				(88,445)		
Series A preferred dividends		(10,745)				
Net income (loss) available to common stockholders	$	(1,233,407)	$	(142,330)	$	(1,403)
Net income (loss) per share of common stock:						
Basic	$	(3.25)	$	(0.91)	$	(0.05)
Diluted	$	(3.25)	$	(0.91)	$	(0.05)
Weighted average common shares outstanding:						
Basic		379,621		156,494		26,258
Diluted		379,621		156,494		26,258

The accompanying notes are an integral part of these consolidated financial statements.

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HALCÓN RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	December 31, 2013	December 31, 2012
Current assets:		
Cash	$ 2,834	$ 2,506
Accounts receivable	312,518	262,809
Receivables from derivative contracts	2,028	7,428
Current portion of deferred income taxes		5,307
Inventory	5,148	3,116
Prepaids and other	16,098	6,691
Total current assets	338,626	287,857
Oil and natural gas properties (full cost method):		
Evaluated	4,960,467	2,669,245
Unevaluated	2,028,044	2,326,598
Gross oil and natural gas properties	6,988,511	4,995,843
Less accumulated depletion	(2,189,515)	(588,207)
Net oil and natural gas properties	4,798,996	4,407,636
Other operating property and equipment:		
Gas gathering and other operating assets	125,837	59,748
Less accumulated depreciation	(8,461)	(8,119)
Net other operating property and equipment	117,376	51,629
Other noncurrent assets:		
Goodwill		227,762
Receivables from derivative contracts	22,734	371
Debt issuance costs, net	64,308	51,609
Deferred income taxes	8,474	
Equity in oil and gas partnerships	4,463	11,137
Funds in escrow and other	1,514	3,024
Total assets	$ 5,356,491	$ 5,041,025
Current liabilities:		

Accounts payable and accrued liabilities	$ 636,589	$ 590,551
Liabilities from derivative contracts	17,859	10,429
Asset retirement obligations	71	2,319
Current portion of deferred income taxes	8,474	
Current portion of long-term debt	1,389	
Promissory notes		74,669
Total current liabilities	664,382	677,968
Long-term debt	3,183,823	2,034,498
Other noncurrent liabilities:		
Liabilities from derivative contracts	19,333	2,461
Asset retirement obligations	39,186	72,813
Deferred income taxes		160,055
Other	2,157	10
Commitments and contingencies (Note 10)		
Mezzanine equity:		
Preferred stock: 1,000,000 shares of $0.0001 par value authorized; no and 10,880 shares of 8% Automatically Convertible, issued and outstanding as of December 31, 2013 and 2012, respectively		695,238
Stockholders' equity:		
Preferred stock: 1,000,000 shares of $0.0001 par value authorized; 345,000 and no shares of 5.75% Cumulative Perpetual Convertible Series A, issued and outstanding as of December 31, 2013 and 2012, respectively		
Common stock: 670,000,000 and 336,666,666 shares of $0.0001 par value authorized; 415,729,962 and 259,802,377 shares issued; 415,729,962 and 258,152,468 shares outstanding at December 31, 2013 and 2012, respectively	41	26
Additional paid-in capital	2,953,786	1,681,717
Treasury stock: no and 1,649,909 shares at December 31, 2013 and 2012, respectively, at cost		(9,298)
Accumulated deficit	(1,506,217)	(274,463)
Total stockholders' equity	1,447,610	1,397,982
Total liabilities and stockholders' equity	$ 5,356,491	$ 5,041,025

The accompanying notes are an integral part of these consolidated financial statements.

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HALCÓN RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands)

	Preferred Stock		Common Stock		Additional Paid-In	Treasury Stock		Accumulated	Stockholders' Equity
	Shares	Amount	Shares	Amount	Capital	Shares	Amount	Deficit	(Deficit)
Balances at January 1, 2011		$	27,533	3	$ 226,047	1,404	$ (6,976)	$ (219,175)	$ (101)
Long-term incentive plan grants			280						
Long-term incentive plan forfeitures			(118)						
Net loss								(1,403)	(1,403)
Repurchase of stock						46	(183)		(183)
Share-based compensation					3,367				3,367
Balances at December 31, 2011			27,695	3	229,414	1,450	(7,159)	(220,578)	1,680
Warrants issued					43,590				43,590
Sale of common stock			115,232	11	568,989				569,000
Reverse-stock-split rounding			4						
Sale of preferred stock	4	311,556							311,556
Preferred stock conversion	(4)	(385,476)	44,445	5	385,471				
Offering costs		(14,525)			(5,078)				(19,603)
Common stock issuance			72,114	7	452,032				452,039
Net loss								(53,885)	(53,885)
Preferred beneficial conversion feature					88,445				88,445
Non-cash preferred dividend		88,445			(88,445)				
Long-term incentive plan grants			312						
Repurchase of stock						200	(2,139)		(2,139)
Share-based compensation					7,299				7,299
Balances at December 31, 2012			259,802	26	1,681,717	1,650	(9,298)	(274,463)	1,397,982
Net loss								(1,222,662)	(1,222,662)
Dividends on Series A preferred stock			2,045		9,092			(9,092)	
Preferred stock conversion			108,801	11	695,227				695,238
Sale of Series A preferred stock	345				345,000				345,000
Common stock issuance			43,700	4	222,866				222,870
Offering costs					(17,346)				(17,346)
Long-term incentive plan grants			3,267						
Long-term incentive plan forfeitures			(205)						
Reduction in shares to cover individuals' tax withholding			(30)		(148)				(148)
Retirement of shares in treasury			(442)		(2,492)	(442)	2,492		
Long-term incentive plan grants issued out of treasury			(1,208)		(6,806)	(1,208)	6,806		
Share-based compensation					26,676				26,676
Balances at December 31, 2013	345	$	415,730	41	$ 2,953,786		$	$ (1,506,217)	$ 1,447,610

The accompanying notes are an integral part of these consolidated financial statements.

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HALCÓN RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2013	**2012**	**2011**
Cash flows from operating activities:			
Net income (loss)	$ (1,222,662)	$ (53,885)	$ (1,403)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depletion, depreciation and accretion	463,655	90,284	22,986
Full cost ceiling impairment	1,147,771		
Other operating property and equipment impairment	67,454		
Goodwill impairment	228,875		
Deferred income tax provision (benefit)	(159,239)	(13,060)	6,549
Share-based compensation, net	17,112	4,573	3,584
Unrealized loss (gain) on derivative contracts	8,728	11,727	(2,954)
Amortization and write-off of deferred loan costs	2,656	6,212	3,663
Non-cash interest and amortization of discount and premium	2,025	9,387	362
Other expense (income)	1,427	(352)	223
Change in assets and liabilities, net of acquisitions:			
Accounts receivable	(96,216)	(93,120)	295
Inventory	(504)	1,194	(927)
Derivative premium			4,889
Prepaids and other	(8,734)	(749)	403
Accounts payable and accrued liabilities	41,576	122,149	(7,835)
Net cash provided by (used in) operating activities	493,924	84,360	29,835
Cash flows from investing activities:			
Oil and natural gas capital expenditures	(2,380,445)	(1,183,295)	(25,214)
Proceeds received from sales of oil and natural gas assets	448,299	21,964	462
Acquisition of GeoResources, Inc., net of cash acquired		(579,497)	
Acquisition of East Texas Assets		(296,139)	
Acquisition of Williston Basin Assets	(32,713)	(756,056)	
Other operating property and equipment capital expenditures	(139,295)	(38,478)	(672)
Funds held in escrow and other	3,455	(965)	48
Net cash provided by (used in) investing activities	(2,100,699)	(2,832,466)	(25,376)
Cash flows from financing activities:			
Proceeds from borrowings	3,725,000	2,466,608	250,167
Repayments of borrowings	(2,644,400)	(655,000)	(245,621)
Debt issuance costs	(23,873)	(52,878)	(7,825)
Offering costs	(17,346)	(18,619)	(985)
Common stock repurchased		(2,139)	(183)
Series A preferred stock issued	345,000		
Preferred stock issued		311,556	
Preferred beneficial conversion feature		88,445	
Common stock issued	222,870	569,000	
Warrants issued		43,590	
Other	(148)		

Net cash provided by (used in) financing activities		1,607,103		2,750,563		(4,447)
Net increase (decrease) in cash		328		2,457		12
Cash at beginning of period		2,506		49		37
Cash at end of period	$	2,834	$	2,506	$	49
Supplemental cash flow information:						
Cash paid for interest, net of capitalized interest	$	25,462	$	11,705	$	554
Cash paid for income taxes		9,014		89		15,326
Disclosure of non-cash investing and financing activities:						
Accrued capitalized interest	$	9,890	$	33,814	$	
Asset retirement obligations		(39,472)		8,587		956
Non-cash preferred dividend				88,445		
Series A preferred dividends paid in common stock		9,092				
Payment-in-kind interest				14,669		
Common stock issued for GeoResources, Inc.				321,416		
Common stock issued for East Texas Assets				130,623		
Preferred stock issued for Williston Basin Assets				695,238		
Current notes payable issued for oil and natural gas properties				74,669		
Payable for acquisition of oil and natural gas properties		2,157				

The accompanying notes are an integral part of these consolidated financial statements.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

Halcón Resources Corporation (Halcón or the Company) is an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich assets in the United States. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries and an equity method investment. The Company operates in one segment which focuses on oil and natural gas acquisition, production, exploration and development. The Company's oil and natural gas properties are managed as a whole rather than through discrete operating areas. Operational information is tracked by operating area; however, financial performance is assessed as a whole. Allocation of capital is made across the Company's entire portfolio without regard to operating area. All intercompany accounts and transactions have been eliminated. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

During the year ended 2013, the Company determined that *"Net cash provided by operating activities*" and "*Net cash used in investing activities*" for the year ended December 31, 2012 were both overstated by $33.8 million as a result of the inclusion of capitalized non-cash interest in the change in "*Accounts payable and accrued liabilities*" line item in operating cash flows and "*Oil and natural gas capital expenditures*" and "*Other operating property and equipment capital expenditures*" in investing cash flows. The Company has corrected the error, which had no impact to the net cash flows for the period, and provided related supplemental non-cash information in the accompanying consolidated statements of cash flows for the year ended December 31, 2012.

Use of Estimates

The preparation of the Company's consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company's management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Estimates and assumptions that, in the opinion of management of the Company, are significant include oil and natural gas revenue accruals, capital and operating expense accruals, oil and natural gas reserves, depletion relating to oil and natural gas properties, asset retirement obligations, fair value estimates, beneficial conversion feature estimates and income taxes. The Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company's operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company's consolidated financial statements.

Accounts Receivable and Allowance for Doubtful Accounts

The Company's accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. Accounts receivable are recorded at the amount due, less an allowance for doubtful accounts, when applicable. The Company establishes provisions for losses on accounts receivable if it determines that collection of all or part of the outstanding balance is doubtful. The

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

Company regularly reviews collectability and establishes or adjusts the allowance for doubtful accounts as necessary using the specific identification method. There were no significant allowances for doubtful accounts as of December 31, 2013 or 2012.

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration and development of proved and unproved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company reviews its unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization. Investments in unevaluated oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress, qualify for interest capitalization. The capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred that are excluded from the full cost pool; however, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period.

Other Operating Property and Equipment

Gas gathering systems and equipment are recorded at cost. Depreciation is calculated using the straight-line method over a 30-year estimated useful life. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life or productive capacity of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The Company capitalized $157.6 million and $39.9 million as of December 31, 2013 and 2012, respectively, related to the construction of its gas gathering systems before impairments.

Other operating assets are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: automobiles and computers, three years; computer software, leasehold improvements, fixtures, furniture and equipment, five years or the lesser of lease term; trailers, seven years; heavy equipment, ten years; and an airplane and buildings, twenty years. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

incurred. Material expenditures which increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset.

The Company reviews its gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate gas gathering systems and equipment and other operating assets for impairment as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of its gas gathering systems and equipment and other operating assets at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods. For the year ended December 31, 2013, the Company recorded a non-cash impairment charge of $67.5 million in *"Other operating property and equipment impairment"* in the Company's consolidated statements of operations and in *"Gas gathering and other operating assets"* in the Company's consolidated balance sheets. The impairment relates to the Company's gross investment of $72.1 million in gas gathering infrastructure that will not be economically recoverable due to the Company's shift in exploration, drilling and developmental plans from the Woodbine to El Halcón during the third quarter of 2013. See Note 5, *"Oil and Natural Gas Properties,"* for additional discussion regarding related factors during the third quarter of 2013 that contributed to this impairment.

In accordance with ASC 820, *Fair Value Measurements and Disclosures* (ASC 820), a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The estimate of the fair value of the Company's gas gathering systems was based on an income approach that estimated future cash flows associated with those assets, which resulted in negative net cash flows due to insufficient throughput of natural gas volumes and certain fixed costs necessary to operate and maintain the assets. This estimation includes the use of unobservable inputs, such as estimated future production, gathering and compression revenues and operating expenses. The use of these unobservable inputs results in the fair value estimate of the Company's gas gathering systems being classified as Level 3.

Revenue Recognition

Revenues from the sale of crude oil, natural gas, and natural gas liquids are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. The Company follows the entitlement method of accounting for natural gas sales, recognizing as revenues only its net interest share of all production sold. Any amount attributable to the sale of production in excess of or less than the Company's net interest is recorded as a gas balancing asset or liability. At December 31, 2013 and 2012 the Company's gas imbalances were immaterial.

Concentrations of Credit Risk

The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners consist primarily of independent oil and natural gas producers. If

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

the oil and natural gas exploration and production industry in general was adversely affected, the ability of the Company's joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, the Company has not experienced any significant losses from uncollectible accounts. In 2013, four individual purchasers of the Company's production, Shell Trading US Co. (STUSCO), Sunoco Partners Marketing & Terminals, L.P. (Sunoco), Arrow Field Services LLC and Suncor Energy Marketing Inc., each accounted for more than 10% of its total sales, collectively representing 63% of the Company's total sales for the year. In 2012, two individual purchasers of the Company's production, STUSCO and Sunoco, each accounted for approximately 20% and 19%, respectively, of its total sales. In 2011, STUSCO accounted for $70.4 million, or 68%, of the Company's oil and natural gas revenue for the year. No other purchaser accounted for 10% or more of its oil and natural gas revenue during 2011.

Risk Management Activities

The Company follows ASC 815, *Derivatives and Hedging* (ASC 815). From time to time, the Company may hedge a portion of its forecasted oil, natural gas, and natural gas liquids production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company recognized all derivative instruments as either assets or liabilities in the consolidated balance sheets at fair value. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in "*Net gain (loss) on derivative contracts*" on the consolidated statements of operations.

Income Taxes

The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

The Company follows ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the consolidated financial statements.

The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

The Company has no liability for unrecognized tax benefits as of December 31, 2013 and 2012. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the consolidated statements of operations or consolidated balance sheets as of December 31, 2013. In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease within the next twelve months.

The Company includes interest and penalties relating to uncertain tax positions within "*Interest expense and other, net*" on the Company's consolidated statements of operations. Refer to Note 12, "*Income Taxes,*" for more details.

Generally, the Company's tax years 2010 through 2013 are either currently under audit or remain open and subject to examination by federal tax authorities or the tax authorities in Louisiana, Mississippi, North Dakota, Oklahoma, Texas, Ohio and Pennsylvania which are the jurisdictions in which the Company has had its principal operations. In certain of these jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination. Additionally, it is important to note that years are open for examination until the statute of limitations in each respective jurisdiction expires.

Tax audits may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which may be due upon the conclusion of these audits. Estimates of these tax liabilities are made based upon prior experience and are updated for changes in facts and circumstances. However, due to the uncertain and complex application of tax regulations, it is possible that the ultimate resolution of audits may result in liabilities which could be materially different from these estimates.

Asset Retirement Obligations

ASC 410, *Asset Retirement and Environmental Obligations* (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells and gas gathering systems and equipment. The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should these indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells and gas gathering systems and equipment as these obligations are incurred.

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1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350, *Intangibles Goodwill and Other* (ASC 350) requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if events occur or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. However, the Company has only one reporting unit. The Company's goodwill as of December 31, 2012 relates to its acquisition of GeoResources. Refer to Note 4, *"Acquisitions and Divestitures"* for more details regarding the merger between the Company and GeoResources. The Company performs its goodwill impairment test annually, using a measurement date of July 1, or more often if circumstances require.

The Company performed its annual goodwill impairment test during the third quarter of 2013, and based on this review, the Company recorded a non-cash impairment charge of $228.9 million to reduce the carrying value of goodwill to zero. The Company has recorded the goodwill impairment in *"Goodwill impairment"* in the Company's consolidated statements of operations. In the first step of the goodwill impairment test, the Company determined that the fair value of its reporting unit was less than the carrying amount, including goodwill, primarily due to pricing deterioration in the NYMEX forward pricing curve coupled with less favorable oil price differentials in the Company's core areas, both factors which adversely impacted the fair value of the Company's proved reserves. Therefore, the Company performed the second step of the goodwill impairment test, which led the Company to conclude that there would be no remaining implied fair value attributable to goodwill.

In estimating the fair value of its reporting unit, the Company used a combination of the income and market approaches. For purposes of estimating the fair value of the Company's oil and natural gas proved reserves, an income approach was used which estimated fair value based on the anticipated cash flows associated with the Company's proved reserves, discounted using a weighted average cost of capital rate. In estimating the fair value of the Company's unproved acreage, a market approach was used in which a review of recent transactions involving properties in the same geographical location indicated the fair value of the Company's unproved acreage from a market participant perspective.

The estimation of the fair value of the Company's reporting unit includes the use of unobservable inputs, such as estimates of proved reserves, unproved acreage values, the weighted average cost of capital (discount rate), future pricing beyond a certain period and estimated future capital and operating costs. The use of these unobservable inputs results in the fair value estimate being classified as Level 3. Although the Company believes the assumptions and estimates used in the fair value calculation of its reporting unit are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating the fair value of the reporting unit and performing the goodwill impairment test are inherently uncertain and require management judgment.

401(k) Plan

The Company sponsors a 401(k) tax deferred savings plan, whereby the Company matches a portion of employees' contributions in cash. Participation in the plan is voluntary and all employees of the Company who are 18 years of age are eligible to participate. The Company provided matching contributions of $4.9 million, $1.8 million, and $0.7 million in 2013, 2012, and 2011, respectively. As of January 1, 2013, the Company matches employee contributions dollar-for-dollar on the first 10% of an employee's pre-tax earnings, subject to individual IRS limitations.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

Recently Issued Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-11, *Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11), which enhances disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position. This pronouncement was issued to facilitate comparison between financial statements prepared on the basis of accounting principles generally accepted in the United States and International Financial Reporting Standards. In addition, in January 2013, the FASB issued ASU No. 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* (ASU 2013-01), which requires clarification of the specific instruments that should be considered in the offsetting disclosures. These updates are effective for annual and interim reporting periods beginning on or after January 1, 2013 and are to be applied retroactively for all comparative periods presented. The adoption of ASU 2011-11 and ASU 2013-01 resulted in new disclosures related to the Company's derivative activities. See further information at Note 8, *"Derivative and Hedging Activities."*

In February 2013, the FASB issued ASU No. 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for which the Total Amount of the Obligation is Fixed at the Reporting Date* (ASU 2013-04). ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements, such as debt arrangements, other contractual obligations and settled litigation and judicial rulings. This pronouncement must be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company is currently assessing the impact, if any, that the adoption of ASU 2013-04 will have on its operating results, financial position and disclosures.

In February 2013, the FASB issued ASU No. 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists* (ASU 2013-11). ASU 2013-11 provides explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This pronouncement should be applied prospectively to all unrecognized tax benefits that exist at the effective date and retrospective application is permitted. ASU 2013-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company is currently assessing the impact, if any, that the adoption of this pronouncement will have on its operating results and financial position.

2. RECAPITALIZATION

On December 21, 2011, the Company entered into a Securities Purchase Agreement (the Purchase Agreement) with HALRES LLC, formerly Halcón Resources, LLC (HALRES), a related party. Pursuant to the Purchase Agreement, (i) HALRES purchased and the Company sold 73.3 million shares of the Company's common stock (the Shares) for a purchase price of $275 million and (ii) HALRES purchased and the Company issued a senior convertible promissory note in the original principal amount of $275 million (the 2017 Note) convertible into common stock at $4.50 per share, subject to adjustment under certain circumstances, together with five year warrants (the February 2012 Warrants) to purchase 36.7 million shares of the Company's common stock at an exercise price of $4.50 per share (the Recapitalization), subject to adjustment under certain circumstances. The 2017 Note is convertible after February 8, 2014 and if converted, would currently entitle the holder to 64.4 million

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. RECAPITALIZATION (Continued)

shares of common stock. The Company and HALRES closed the transaction contemplated by the Purchase Agreement on February 8, 2012.

In January 2012, shareholders holding a majority of the Company's outstanding shares of common stock approved the issuance of the Shares, the 2017 Note and the February 2012 Warrants pursuant to the terms of the Purchase Agreement. Additionally, the board of directors approved, effective upon the closing (i) the Company's certificate of incorporation was amended to (a) the Company's authorized shares of common stock were increased from 100 million shares to 1.01 billion shares, both of which were before the one-for-three reverse stock split; (b) a one-for-three reverse stock split of the Company's common stock was affected (which reduced the Company's authorized shares of common stock from 1.01 billion to 336.7 million shares); and (c) the name of the Company was changed from RAM Energy Resources, Inc. to Halcón Resources Corporation; (ii) the Company's 2006 Long-Term Incentive Plan (the Plan) was amended to increase the number of shares that may be issued under the Plan from 2.5 million to 3.7 million shares; and (iii) on an advisory (non-binding) basis, the payments made to the Company's named executive officers in connection with the transactions contemplated by the Purchase Agreement.

The closing of the transaction resulted in a change in control of the Company. Material events and items resulting from the transaction include the following:

- completion of transactions contemplated by the Purchase Agreement and shareholder approval of the matters as discussed above;
- the resignation and termination of the Company's four executive officers and the resignation of certain other officers;
- change in control payments of $4.6 million to the officers of the Company recorded in general and administrative expense;
- change in control payment of $0.8 million pursuant to a retainer agreement with the Company's then outside law firm recorded in general and administrative expense;
- accelerated vesting of all unvested employee restricted stock shares and accelerated vesting and exercise of all unvested stock appreciation rights resulting in $4.3 million of share-based compensation expense recorded in general and administrative expense;
- payoff and termination of the Company's existing March 2011 credit facilities of $133.0 million plus accrued interest, as well as the expensing of the related unamortized debt issuance costs of $2.9 million;
- payoff and termination of the Company's second lien term facility of $75.0 million plus accrued interest and a prepayment fee of $1.5 million, as well as the expensing of the related unamortized debt issuance costs of $2.9 million; and
- closing costs of $11.2 million related to engagement fees and various professional fees including $2.5 million recorded in general and administrative expense related to a termination fee pursuant to a previous engagement.

In January 2012, the Company approved a one-for-three reverse stock split, which was implemented on February 10, 2012. Retroactive application of the reverse stock split is required and all

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. RECAPITALIZATION (Continued)

share and per share information included for all periods presented in these consolidated financial statements reflects the reverse stock split.

In February 2012, the transaction with HALRES resulted in an "ownership change" as defined under Section 382 of the Internal Revenue Code of 1986, as amended. As a consequence, the Company has additional limitations on its ability to use the net operating losses it accrued before the ownership change as a deduction against any taxable income the Company realizes after the ownership change.

3. RESTRUCTURING

In the fourth quarter of 2013, in conjunction with the Company's divestitures of certain non-core assets, see Note 4, *"Acquisitions and Divestitures,"* the Company incurred and settled approximately $4.0 million in severance costs related to the termination of certain employees in these non-core areas. The severances were complete with the closing of the final non-core asset sale in December 2013.

In March 2012, the Company announced its intention to close its Plano, Texas office and began the process of relocating key administrative functions to Houston, Texas (the Restructuring). As part of the Restructuring, the Company offered certain severance and retention benefits, collectively known as the Severance Program, to the affected employees. The total expense of the Severance Program was approximately $2.9 million and related costs were recognized as restructuring expense over the requisite service periods through May 2013, as applicable. Following is a reconciliation of the beginning and ending liability balance:

	Severance Program (In thousands)
Beginning balance, December 31, 2012	$ 2,131
Severance and Retention payments	(2,627)
Net increase in accrual	496
Ending balance, December 31, 2013	$

These costs were recorded in "*Restructuring*" on the consolidated statements of operations.

4. ACQUISITIONS AND DIVESTITURES

Acquisitions

Williston Basin Assets

On December 6, 2012, the Company completed the acquisition of two wholly-owned subsidiaries of Petro-Hunt Holdings, LLC and Pillar Holdings, LLC (the Petro-Hunt Parties), which owned acreage prospective for the Bakken / Three Forks formations located in North Dakota, in Williams, Mountrail, McKenzie and Dunn counties (the Williston Basin Assets). The Company completed the acquisition of the Williston Basin Assets for total consideration of approximately $1.5 billion, consisting of approximately $788.8 million in cash and approximately 10,880 shares of the Company's preferred stock that automatically converted into 108.8 million shares of Halcón common stock on January 18, 2013 (equivalent to a conversion price of approximately $7.45 per share of Halcón common stock based on the liquidation preference), following stockholder approval of such conversion and an amendment to Halcón's certificate of incorporation to increase the number of shares of common stock that Halcón is

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

authorized to issue (the Williston Basin Acquisition). The Williston Basin Acquisition significantly expanded the Company's presence in North Dakota, adding undeveloped acreage, oil and natural gas reserves and production to its existing asset base and operations in this area.

The transaction had an effective date of June 1, 2012 and was subject to customary closing conditions, as well as the execution and delivery of certain other agreements, including a Registration Rights Agreement, dated December 6, 2012. In accordance with the Registration Rights Agreement, as amended, on September 27, 2013, the Company filed a shelf registration statement providing for the resale of shares of the Company's common stock issued to the Petro-Hunt Parties in the acquisition.

The Williston Basin Acquisition was accounted for as a business combination in accordance with ASC No. 805, *Business Combinations* (ASC 805) which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. The estimated fair value of the properties approximates the fair value of consideration and as a result no goodwill was recognized.

The following table summarizes the consideration paid to acquire the Williston Basin Assets, as well as the amounts of assets acquired and liabilities assumed as of the acquisition date (in thousands):

Purchase Price:(1)		
Halcón preferred shares issued to Williston Basin Assets Sellers(2)	$	695,238
Cash consideration paid to Williston Basin Assets Sellers(3)		788,769
Total purchase price	$	1,484,007

Estimated Fair Value of Liabilities Assumed:		
Current liabilities	$	7,211
Asset retirement obligations		5,207
Amount attributable to liabilities assumed		12,418
Total purchase price plus liabilities assumed	$	1,496,425

Estimated Fair Value of Assets Acquired:		
Current assets	$	4,264
Evaluated oil and natural gas properties(4)(5)		630,431
Unevaluated oil and natural gas properties		861,730
Amount attributable to assets acquired	$	1,496,425

Goodwill	

(1) Based on the terms of the reorganization and interest purchase agreement, consideration paid by Halcón consisted of $788.8 million in cash plus approximately 10,880 shares of convertible preferred stock. The total purchase price is based upon the fair value of the preferred shares which was determined using the lowest price of $6.39 per share of the Company's common stock on December 6, 2012, the number of convertible preferred shares issued and the conversion rate of each convertible preferred share to 10,000 shares of common stock. Cash consideration has been adjusted for customary post-closing items.

(2) Represents the fair value of convertible preferred stock par value $0.0001 per share issued to sellers with each preferred share convertible into 10,000 shares of common

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4. ACQUISITIONS AND DIVESTITURES (Continued)

stock. The preferred shares were presented on the balance sheet as mezzanine equity due to the fact that the conversion of the preferred shares to common shares was still contingent upon shareholder approval at the December 31, 2012 balance sheet date. See further discussion of the preferred shares at Note 11, *"Preferred Stock and Stockholders' Equity"*.

(3) Represents amount of cash consideration, adjusted for customary post-closing items, for the purchase of the Williston Basin Assets funded by the issuance of the $750 million 8.875% senior notes with net proceeds of $725.6 million and borrowings under the Senior Credit Agreement revolver. See discussion of 8.875% note and Senior Credit Agreement at Note 6, *"Long-term Debt"*.

(4) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount for future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see Note 7, *"Fair Value Measurements"*.

(5) Weighted average commodity prices utilized in the determination of the pro forma fair value of oil and natural gas properties were $95.17 per barrel of oil and $10.85 per Mcf of natural gas, after adjustment for transportation fees and regional price differentials. The pricing used in the determination of fair value reflects the differential applied to future prices; differentials for natural gas reflect relatively higher Btu gas content.

GeoResources, Inc.

On August 1, 2012, the Company completed an acquisition of GeoResources, Inc. (GeoResources) by means of the merger of GeoResources into a wholly-owned subsidiary of the Company (the Merger) and began reflecting GeoResources' results of operations in the Company's consolidated statements of operations. In connection with the Merger, each share of GeoResources common stock issued and outstanding immediately prior to the effective date of the Merger was converted into the right to receive $20.00 in cash and 1.932 shares of the Company's common stock.

In the Merger, the Company issued a total of approximately 51.3 million shares of its common stock and paid approximately $531.5 million in cash to former GeoResources stockholders, resulting in a total purchase price plus liabilities assumed of approximately $1.3 billion. The acquisition expanded the Company's presence in the Bakken / Three Forks formations of North Dakota, and the Austin Chalk Trend and Eagle Ford Shale in Texas, adding oil and natural gas reserves and production to its existing asset base in these areas.

The acquisition was accounted for as a business combination in accordance with ASC 805 which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. GeoResources results of operations are reflected in the Company's consolidated statements of operations, beginning August 1, 2012.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

The following table summarizes the consideration paid to acquire GeoResources and the estimated values of assets acquired and liabilities assumed in the accompanying audited consolidated balance sheets based on their fair values on August 1, 2012 (in thousands, except stock price):

Purchase price:[(1)]		
Shares of Halcón common stock issued to GeoResources' stockholders		50,378
Shares of Halcón common stock issued to GeoResources' stock option holders		966
Total Halcón common stock issued		51,344
Halcón common stock price	$	6.26
Fair value of common stock issued	$	321,416
Cash consideration paid to GeoResources' stockholders[(2)]		521,526
Cash consideration paid to GeoResources' stock option holders[(2)]		9,996
Fair value of warrants assumed by Halcón[(3)]		1,474
Total purchase price	$	854,412
Estimated fair value of liabilities assumed:		
Current liabilities	$	112,412
Deferred tax liability[(4)]		188,385
Asset retirement obligations		28,064
Other non-current liabilities		80,024
Amount attributable to liabilities assumed	$	408,885
Total purchase price plus liabilities assumed	$	1,263,297
Estimated fair value of assets acquired:		
Current assets	$	108,067
Evaluated oil and natural gas properties[(5)(6)]		458,564
Unevaluated oil and natural gas properties		454,000
Net other operating property and equipment		1,179
Equity in oil and gas partnerships[(7)]		10,967
Other non-current assets		1,645

Amount attributable to assets acquired	$	1,034,422
Goodwill[(8)]	$	228,875

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(1) Under the terms of the Merger Agreement, consideration paid by Halcón consisted of $20.00 in cash plus 1.932 shares of Halcón common stock for each share of GeoResources common stock. The total purchase price was based upon the price of Halcón common stock on the closing date of the transaction, August 1, 2012, and approximately 26.6 million shares of GeoResources common stock outstanding at the effective time of the Merger. The Company issued a total of 51.3 million shares of its common stock and paid $531.5 million in cash to former GeoResources stockholders in exchange for their shares of GeoResources common stock. Cash consideration has been adjusted for customary post-closing items.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

(2)

Components of cash flow for the Merger (in thousands):

Total cash consideration for Merger and stock options[(i)]	$ 531,522
Retirement of GeoResources' long-term debt[(ii)]	80,328
Cash acquired on date of Merger	(32,353)
Total cash outflows, net	$ 579,497

(i)

The majority of the cash consideration was funded by the net proceeds from the issuance of the 9.75% senior notes.

(ii)

Includes accrued interest and fees.

(3)

The $1.5 million fair value of the assumed warrants was calculated using a Black-Scholes valuation model with assumptions for the following variables: price of Halcón stock on the closing date of the merger; risk-free interest rates; and expected volatility. The assumed warrants were classified as liabilities as of December 31, 2012 as the warrant holders can receive cash. The assumed warrants were classified as current liabilities at December 31, 2012 because all the warrants expired in 2013.

(4)

Halcón received carryover tax basis in GeoResources' assets and liabilities because the Merger was not a taxable transaction under the United States Internal Revenue Code of 1986, as amended. Based upon the purchase price allocation, a step-up in financial reporting carrying value related to the property acquired from GeoResources resulted in a Halcón deferred tax liability of approximately $188.4 million, an increase of approximately $127.0 million to GeoResources' existing $61.4 million deferred tax liability.

(5)

Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $6.65 per Mcf of natural gas, $35.66 per barrel of oil equivalent for natural gas liquids and $98.37 per barrel of oil, after adjustment for transportation fees and regional price differentials.

(6)

The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount for future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see Note 7, *"Fair Value Measurements"*.

(7)

As a part of the Merger, the Company acquired investments, in the form of general partnership interests, in two affiliated partnerships, SBE Partners LP (SBE Partners) and OKLA Energy Partners LP (OKLA Energy). These partnerships hold direct working interests in oil and natural gas properties. The Company's investment in an unconsolidated entity in which the Company does not have a majority interest or control, but does have significant influence, is accounted for under the equity method. The Company holds a 2% general partner interest, in OKLA Energy, which reverts to 35.66% interest when the limited partner realizes a contractually specified rate of return. On July 25, 2013, the Company sold its general partner interest in OKLA Energy to a private buyer. The Company holds a 30% general partner interest in SBE Partners. Under the equity method of accounting the Company records its net share of income and expenses in *"Interest expense and other, net"* on the consolidated statements of operations. Contributions to the

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

investment increase the Company's investment while distributions from the investment decrease the Company's carrying value of the investment in *"Equity in oil and gas partnerships"* on the consolidated balance sheets. The Company reviews its equity method investment for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred.

(8) Goodwill was determined as the excess consideration transferred over the fair value of the GeoResources net assets acquired on August 1, 2012. Goodwill recognized will not be deductible for tax purposes. The Company performs its goodwill impairment test annually, using a measurement date of July 1, or more often if circumstances require. Refer to Note 1, *"Summary of Significant Events and Accounting Policies,"* for additional discussion of the Company's goodwill impairment test and the Company's impairment of its goodwill balance during 2013.

East Texas Assets

In August 2012, the Company completed the acquisition of oil and natural gas leaseholds in East Texas (the East Texas Assets) from CH4 Energy II, LLC, PetroMax Leon, LLC, Petro Texas LLC, King King LLC and several other selling parties for total consideration of $426.8 million comprised of $296.1 million in cash and 20.8 million shares of the Company's common stock (the East Texas Acquisition). The East Texas Acquisition expanded the Company's presence in East Texas, adding oil and natural gas reserves and production to its existing asset base in this area. On August 27, 2012 the Company filed a registration statement with the SEC that registered under the Securities Act the resale of the shares of common stock issued as consideration in the East Texas Acquisition.

The East Texas Acquisition was accounted for as a business combination in accordance with ASC 805 which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. The effective date of the East Texas Acquisition was April 1, 2012. The estimated fair value of the properties approximates the fair value of consideration and as a result no goodwill was recognized.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

The following table summarizes the consideration paid to acquire the properties and the amounts of the assets acquired and liabilities assumed as of the acquisition date (in thousands, except stock prices):

Purchase price:[1]		
Shares of Halcón common stock issued on August 1, 2012		16,460
Shares of Halcón common stock issued on August 2, 2012		4,310
Total Halcón common stock issued		20,770
Halcón common stock price on August 1, 2012	$	6.26
Halcón common stock price on August 2, 2012	$	6.40
Fair value of Halcón common stock issued	$	130,623
Cash consideration paid to sellers of East Texas Assets		296,139
Total purchase price	$	426,762
Estimated fair value of liabilities assumed:		
Current liabilities	$	192
Asset retirement obligations		337
Amount attributable to liabilities assumed	$	529
Total purchase price plus liabilities assumed	$	427,291
Estimated fair value of assets acquired:		
Evaluated oil and natural gas properties[2][3]	$	337,303
Unevaluated oil and natural gas properties		89,988
Amount attributable to assets acquired	$	427,291
Goodwill	$	

(1)
Based on the terms of the purchase and sale agreements relating to the East Texas Assets, consideration paid by Halcón at closing consisted of $296.1 million in cash plus 20.8 million shares of Halcón common stock. The total purchase price is based upon the price on August 1, 2012 of $6.26 per share of Halcón's common stock for CH4 Energy II, LLC, PetroMax Leon, LLC and Petro Texas, LLC (Initial Sellers) and price on August 2, 2012 of $6.40 per share of Halcón's common stock for King King LLC. Cash consideration has been adjusted for customary post-closing items. The East Texas Acquisition was partially financed with the net proceeds from the issuance of $750.0 million of 9.75% senior notes and cash on hand. See Note 6, *"Long-Term Debt"* for discussion of the accounting treatment of the 9.75% senior notes.

(2)
The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount for future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see Note 7, *"Fair Value Measurements"*.

(3)
Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $6.26 per Mcf of natural gas, $49.68 per Boe for natural gas liquids and $98.35 per barrel of oil, after adjustment for transportation fees and regional price differentials.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

The following unaudited pro forma combined results of operations are provided for the years ended December 31, 2012 and 2011 as though the Merger, the East Texas Acquisition and the Williston Basin Acquisition had been completed as of the beginning of the comparable prior annual reporting period, or January 1, 2011. The pro forma combined results of operations for the years ended December 31, 2012 and 2011 have been prepared by adjusting the historical results of the Company to include the historical results of GeoResources, the East Texas Assets and the Williston Basin Assets. These supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the Merger, the East Texas Acquisition and the Williston Basin Acquisition or any estimated costs that will be incurred to integrate GeoResources, the Williston Basin Assets and the East Texas Assets. Future results may vary significantly from the results reflected in this unaudited pro forma financial information because of future events and transactions, as well as other factors.

	Years ended December 31,	
	2012	2011
	(Unaudited)	(Unaudited)
	(in thousands, except per share amounts)	
Revenue	$ 608,092	$ 330,491
Net income (loss)	34,895	14,379
Net income (loss) available to Halcón common stockholders	(53,550)	14,466
Pro forma net income (loss) per common share:		
Basic	$ (0.17)	$ 0.07
Diluted	$ (0.17)	$ 0.07

The Company's historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Merger and the acquisitions of the East Texas Assets and the Williston Basin Assets and factually supportable. The unaudited pro forma consolidated results include the historical revenues and expenses of assets acquired and liabilities assumed in the Merger and the acquisitions of the East Texas Assets and the Williston Basin Assets with the following adjustments:

- Adjustment to recognize incremental depletion expense under the full cost method of accounting based on the fair value of the oil and natural gas properties and incremental accretion expense based on the asset retirement costs of the oil and natural gas properties at acquisition;
- Eliminate historical interest expense for GeoResources debt that was extinguished;
- Adjustment to recognize interest expense, net of capitalized interest, for debt issued in connection with the transactions;
- Eliminate transaction costs and non-recurring charges directly related to the transactions that were included in the historical results of operations for GeoResources and the Company in the amount of $59.5 million. Transaction costs directly related to the transactions that do not have a continuing impact on the combined Company's operating results have been excluded from the 2012 and 2011 pro forma earnings;
- Adjustment to recognize pro forma income tax based on an assumed 38% rate;

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

Eliminate historical impairment expense for GeoResources that would not have been incurred under the full cost method of accounting;

Adjustment to convert successful efforts method financial statements of GeoResources to full cost method financial statements to adjust exploration expenses which would have been capitalized under the full cost method of accounting for oil and natural gas activities;

Adjustment to GeoResources' historical revenue to reclass net settlements on commodity derivatives that under cash flow hedge accounting were included in GeoResources' revenues from oil and natural gas sales, and adjustment to reflect unrealized gain on commodity derivatives. In accordance with the Company's accounting policy, it does not apply cash flow hedge accounting treatment and the realized and unrealized gain (loss) on commodity derivatives have been reflected as a gain (loss) on derivative contracts;

Adjustment to recognize the issuance of 51.3 million shares of Halcón common stock as consideration for the GeoResources Merger; and

Adjustment to recognize the issuance of the 20.8 million shares of Halcón common stock as consideration for the acquisition of the East Texas Assets; and

Adjustment to recognize the issuance of Halcón preferred stock as consideration for the Williston Basin Assets that automatically converted to 108.8 million shares of Halcón common stock.

For the year ended December 31, 2012, the Company recognized $19.7 million of oil, natural gas and natural gas liquids sales related to properties acquired in the acquisition of the Williston Basin Assets and $6.7 million of net field operating income (oil, natural gas and natural gas liquids revenues less lease operating expense, workover expense, production taxes, depletion expense and income taxes) related to properties acquired in the acquisition of the Williston Basin Assets. Additionally, non-recurring transaction costs of $14.2 million related to the acquisition of the Williston Basin Assets for the year ended December 31, 2012 are included in the consolidated statements of operations in "*General and administrative"* expenses; these non-recurring transaction costs have been excluded from the pro forma results for all periods presented in the above table.

For the year ended December 31, 2012, the Company recognized $90.8 million of oil, natural gas and natural gas liquids sales and $25.7 million of net field operating income (oil, natural gas and natural gas liquids revenues less lease operating expense, workover expense, production taxes, depletion expense and income taxes) related to properties acquired in the Merger. Additionally, non-recurring transaction costs of $21.5 million related to the Merger for the year ended December 31, 2012 are included in the consolidated statements of operations in "*General and administrative"* expenses; these non-recurring transaction costs have been excluded from the pro forma results for all periods presented in the above table.

For the year ended December 31, 2012, the Company recognized $34.8 million of oil, natural gas and natural gas liquids revenues related to properties acquired in the acquisition of the East Texas Assets and $16.5 million of net field operating income (oil, natural gas and natural gas liquids revenues less lease operating expense, workover expense, production taxes, depletion expense and income taxes) related to properties acquired in the acquisition of the East Texas Assets. Additionally, non-recurring transaction costs of $1.1 million related to the acquisition of the East Texas Assets for the year ended

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

December 31, 2012 are included in the consolidated statements of operations in "*General and administrative"* expenses; these non-recurring transaction costs have been excluded from the pro forma results for all periods presented in the above table.

Other Acquisitions

On December 28, 2012, the Company completed the acquisition of certain oil and natural gas properties, located in Brazos County, Texas, from a group of private sellers for approximately $83.7 million, before customary closing adjustments, consisting of approximately $8.4 million in cash and approximately $75.3 million in promissory notes. The promissory notes had a maturity date of August 30, 2013. The transaction had an effective date of December 1, 2012. Refer to Note 6, *"Long-term Debt,"* for more details regarding the promissory notes.

Divestitures

Non-core Assets

During the third quarter of 2013, the Company entered into three separate purchase and sale agreements with unrelated parties to divest certain distinct non-core assets located throughout the United States for total consideration of approximately $302.0 million, all of which closed by December 31, 2013. The transactions and consideration are subject to customary closing conditions and adjustments, with an effective date of July 1, 2013. Proceeds from the sales were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded. The borrowing base reduction associated with these non-core assets sales was $50.0 million. Following the closing of the last of these three divestitures, on December 20, 2013, the borrowing base under our Senior Credit Agreement was reduced by the $50.0 million to $700.0 million.

Eagle Ford Assets

On July 19, 2013, the Company completed the sale of its interest in Eagle Ford Shale assets located in Fayette and Gonzales Counties, Texas, previously acquired as part of the Merger, to private buyers for proceeds of approximately $147.9 million, before post-closing adjustments. The transaction had an effective date of January 1, 2013. Proceeds from the sale were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded.

Louisiana Properties

On November 29, 2012, the Company completed the sale of certain oil and natural gas properties located in Eloi Bay/Half Moon Lakes Field, Chandeleur Sound Block 71 Field and Quarantine Bay Field to Cox Oil, LLC for $22.0 million in cash, after customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded. The transaction had an effective date of August 1, 2012.

Electra/Burkburnett Field

During 2011, the Company entered into an agreement in principle to sell a majority interest in the Company's Electra / Burkburnett Field to Argent Energy Trust, a recently formed Canadian energy trust. Argent filed a preliminary prospectus with Canadian regulatory authorities for an initial public

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ACQUISITIONS AND DIVESTITURES (Continued)

offering of its trust units in Canada (Argent IPO). The sale of the Company's Electra / Burkburnett Field was contingent upon several conditions, including completion of the Argent IPO. The Argent IPO was not completed and the agreement between the Company and Argent terminated during December 2011. The Company incurred approximately $2.4 million in related fees. Due to the termination of the agreement these fees are reflected in general and administrative expense in 2011.

5. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2013 and 2012 consisted of the following:

	December 31,	
	2013	2012
	(In thousands)	
Subject to depletion	$ 4,960,467	$ 2,669,245
Not subject to depletion:		
Exploration and extension wells in progress	109,279	67,992
Other capital costs:		
Incurred in 2013	750,960	
Incurred in 2012	1,167,805	2,258,606
Incurred in 2011		
Incurred in 2010 and prior		
Total not subject to depletion	2,028,044	2,326,598
Gross oil and natural gas properties	6,988,511	4,995,843
Less accumulated depletion	(2,189,515)	(588,207)
Net oil and natural gas properties	$ 4,798,996	$ 4,407,636

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs are charged to expense.

The Company assesses all properties classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. The Company assesses properties on an individual basis or as a group, if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the full cost ceiling test limitation. During the three months ended September 30, 2013, the Company transferred $655.7 million of unevaluated property costs to the full cost pool primarily related to Woodbine assets in

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. OIL AND NATURAL GAS PROPERTIES (Continued)

East Texas where capital has been reallocated to El Halcón, and certain Utica / Point Pleasant assets in Northwest Pennsylvania related to non-economical drilling results obtained in the third quarter of 2013.

Investments in unevaluated oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress, qualify for interest capitalization. The capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred that are excluded from the full cost pool; however, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The capitalized interest amounts are recorded as additions to unevaluated oil and natural gas properties on consolidated balance sheets. As the costs excluded are transferred to the full cost pool, the associated capitalized interest is also transferred to the full cost pool. For the year ended December 31, 2013 and 2012, the Company capitalized interest costs of $201.5 million and $53.5 million, respectively.

The ceiling test value of the Company's reserves was calculated based on the following prices:

	West Texas Intermediate (per barrel)(1)(2)	Henry Hub (per MMBtu)(3)
December 31, 2013	$ 96.94	$ 3.670
December 31, 2012	$ 94.71	$ 2.757
December 31, 2011	$ 96.19	$ 4.12

(1) First day average of the 12-months ended December 31, 2013 and 2012 spot price, adjusted by lease or field for quality, transportation fees and regional price differentials.

(2) First day average of the 12-months ended December 31, 2011 posted price, adjusted by lease or field for quality, transportation fees and regional price differentials.

(3) First day average of the 12-months ended price, adjusted by lease or field for quality, transportation fees and regional price differentials.

The Company's net book value of oil and natural gas properties at September 30, 2013 and December 31, 2013 exceeded the ceiling amount. The Company recorded a full cost ceiling test impairment before income taxes of $1.1 billion ($727.2 million after taxes) for the year ended December 31, 2013. The combined impact of less favorable oil price differentials adversely affecting proved reserve values and the non-routine transfers of unevaluated Woodbine and Utica / Point Pleasant properties to the full cost pool contributed to the ceiling impairment. At December 31, 2012 and 2011, the Company's net book value of oil and natural gas properties did not exceed the respective ceiling amounts. The Company recorded the full cost ceiling test impairment in *"Full cost ceiling impairment"* in the Company's consolidated statements of operations and in *"Accumulated depletion"* in the Company's consolidated balance sheets.

Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine the Company's actual ceiling test calculation and impairment analyses in future periods.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT

Long-term debt as of December 31, 2013 and 2012 consisted of the following:

	December 31,	
	2013[(1)]	2012[(1)]
	(In thousands)	
Senior revolving credit facility	$	$ 298,000
9.25% $400 million senior notes[(2)]	400,000	
8.875% $1.35 billion senior notes[(3)]	1,372,355	744,421
9.75% $1.15 billion senior notes[(4)]	1,152,099	740,232
8.0% $275 million convertible note[(5)]	259,369	251,845
	$ 3,183,823	$ 2,034,498

(1) Table excludes $1.4 million of deferred premiums on derivative contracts which were classified as current at December 31, 2013. Table excludes $74.7 million of promissory notes which were classified as current at December 31, 2012.

(2) On August 13, 2013, the Company completed the issuance of $400 million principal amount of its 9.25% Senior Notes due 2022. See "9.25% Senior Notes" below for more details.

(3) Amount is net of a $5.1 million and a $5.6 million unamortized discount at December 31, 2013 and, 2012, respectively, related to the issuance of the original 2021 Notes. On January 14, 2013, the Company completed the issuance of an additional $600 million principal amount of its 8.875% Senior Notes. The unamortized premium related to these additional 2021 Notes was approximately $27.5 million at December 31, 2013. See "8.875% Senior Notes" below for more details.

(4) Amount is net of an $8.9 million and a $9.8 million unamortized discount at December 31, 2013 and 2012, respectively, related to the issuance of the original 2020 Notes. On December 19, 2013, the Company completed the issuance of an additional $400 million principal amount of its 9.75% Senior Notes. The unamortized premium related to these additional 2020 Notes was approximately $11.0 million at December 31, 2013. See "9.75% Senior Notes" below for more details.

(5) Amount is net of a $30.3 million and a $37.8 million unamortized discount at December 31, 2013 and 2012, respectively. See "8.0% Convertible Note" below for more details.

Senior Revolving Credit Facility

In connection with the closing of the Recapitalization, discussed in Note 2, *"Recapitalization,"* the Company entered into a senior secured revolving credit agreement (the Senior Credit Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and the other lenders party thereto on February 8, 2012. The Senior Credit Agreement provides for a $1.5 billion facility with a current borrowing base of $700.0 million. Amounts borrowed under the Senior Credit Agreement will mature on February 8, 2017. The borrowing base will be redetermined semi-annually, with the lenders and the Company each having the right to one interim unscheduled redetermination between any

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT (Continued)

two consecutive semi-annual redeterminations. The borrowing base takes into account the Company's oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. The borrowing base is subject to a reduction equal to the product of 0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any future notes or other long-term debt securities that the Company may issue. Funds advanced under the Senior Credit Agreement may be paid down and re-borrowed during the five-year term of the revolver. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 0.50% to 1.50% for ABR-based loans or at specified margins over LIBOR of 1.50% to 2.50% for Eurodollar-based loans. These margins fluctuate based on the Company's utilization of the facility. Advances under the Senior Credit Agreement are secured by liens on substantially all of the Company's properties and assets. The Senior Credit Agreement contains customary representations, warranties and covenants including, among others, restrictions on the payment of dividends on the Company's capital stock and financial covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0.

At December 31, 2013, the Company had no borrowings outstanding, $1.2 million of letters of credit outstanding and $698.8 million of borrowing capacity under the Senior Credit Agreement, of which approximately $629 million was available to us under the indebtedness limitation in our indentures.

On January 25, 2013, the Company entered into the Second Amendment to its Senior Credit Agreement which expanded its ability to enter into certain commodity hedging agreements. On April 26, 2013, the Company entered into the Third Amendment to its Senior Credit Agreement, which, among other things, provided additional flexibility under certain affirmative and negative covenants. On May 8, 2013, the Company entered into the Fourth Amendment to the Senior Credit Agreement which modified the calculation of the interest coverage test, which was superseded by the Sixth Amendment and on June 11, 2013, the Company entered into the Fifth Amendment to the Senior Credit Agreement which permits the Company, among other things, to pay cash dividends to holders of its preferred capital stock.

On October 31, 2013, the Company entered into the Sixth Amendment to the Senior Credit Agreement (the Sixth Amendment). The Sixth Amendment increased the borrowing base to $850.0 million, which was subsequently reduced to $700.0 million upon the closing of the final non-core divestiture in December 2013, as discussed in Note 4, *"Acquisitions and Divestitures."* Additionally, the Sixth Amendment provides for EBITDA (as defined in the Senior Credit Agreement) to be annualized for the next three fiscal quarters for purposes of measuring compliance with the interest coverage test. Specifically, (i) for the fiscal quarter ended December 31, 2013, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the three month period then ended multiplied by 4; (ii) for the fiscal quarter ended March 31, 2014, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the six month period then ended multiplied by 2; and (iii) for the fiscal quarter ended June 30, 2014, the Interest Coverage Ratio shall be calculated by utilizing EBITDA for the nine month period then ended multiplied by 1.333.

At December 31, 2013, the Company was in compliance with the financial debt covenants under the Senior Credit Agreement.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT (Continued)

March 2011 Credit Facilities

The Company's March 2011 credit facilities included a $250.0 million revolving credit facility and a $75.0 million second lien term loan facility (the March 2011 Credit Facilities), replacing the November 2007 facility. SunTrust Bank was the administrative agent for the revolving credit facility, and Guggenheim Corporate Funding, LLC was the administrative agent for the second lien term loan facility. The revolving credit facility allowed for funds advanced to be paid down and re-borrowed during the five-year term of the revolver, and bore interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The second lien term loan facility provided for payments of interest only during its 5.5 year term, and bore interest at LIBOR plus 9.0% with a 2.0% LIBOR floor, or if any period the Company elected to pay a portion of the interest "in kind," then the interest rate would have been LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid in kind by being added to principal. At December 31, 2011, $127.0 million was outstanding under the revolving credit facility and $75.0 million was outstanding under the second lien term loan facility. On February 8, 2012, the Company paid in full the outstanding balances under the revolving credit facility and the second lien term loan facility and both facilities were terminated, resulting in a $1.5 million charge to interest expense related to an early termination penalty.

9.25% Senior Notes

On August 13, 2013, the Company issued at par $400.0 million aggregate principal amount of 9.25% senior notes due 2022 (the 2022 Notes). The net proceeds from the offering of approximately $392.1 million (after deducting commissions and offering expenses) were used to repay a portion of the then outstanding borrowings under the Company's Senior Credit Agreement.

The 2022 Notes bear interest at a rate of 9.25% per annum, payable semi-annually on February 15 and August 15 of each year, beginning on February 15, 2014. The 2022 Notes will mature on February 15, 2022. The 2022 Notes are senior unsecured obligations of the Company, rank equally with all of its current and future senior indebtedness and are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's existing 100% owned subsidiaries. Halcón, the issuer of the 2022 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

In connection with the sale of the 2022 Notes, the Company entered into a registration rights agreement, pursuant to which the Company agreed to conduct a registered exchange offer for the 2022 Notes or cause to become effective a shelf registration statement providing for the resale of the 2022 Notes. In connection with the exchange offer, the Company is required to (a) file an exchange offer registration statement and use its reasonable best efforts to cause such registration statement to become effective, (b) promptly following the effectiveness of such registration statement, offer to exchange new registered notes having terms substantially identical to the 2022 Notes for outstanding 2022 Notes, and (c) keep the registered exchange offer open for not less than 20 business days after the date notice of the exchange offer is mailed to the holders of the 2022 Notes. If the exchange offer is not consummated within 365 days after August 13, 2013, or upon the occurrence of certain other contingencies, the Company has agreed to file a shelf registration statement to cover resales of the 2022 Notes by holders who satisfy certain conditions relating to the provision of information in connection with the shelf registration statement. If the Company fails to comply with certain obligations

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT (Continued)

under the registration rights agreement it will be required to pay liquidated damages in the form of additional cash interest to the holders of the 2022 Notes.

On or before August 15, 2016, the Company may redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net cash proceeds of certain equity offerings at a redemption price of 109.250% of the principal amount plus accrued and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2022 Notes originally issued remains outstanding immediately after the redemption and the redemption occurs within 180 days of the related equity offering. In addition, at any time prior to August 15, 2017, the Company may redeem some or all of the 2022 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at August 15, 2017, plus (ii) any required interest payments due on the notes through August 15, 2017 (excluding currently accrued and unpaid interest) computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

On or after August 15, 2017, the Company may redeem all or a part of the 2022 Notes at any time or from time to time at the redemption prices (expressed as percentages of the principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning August 15, of the years indicated:

Year	Percentage
2017	104.625%
2018	102.313%
2019 and thereafter	100.000%

In addition, upon a change of control of the Company, holders of the 2022 Notes will have the right to require the Company to repurchase all or any part of their 2022 Notes for cash at a price equal to 101% of the aggregate principal amount of the 2022 Notes repurchased, plus any accrued and unpaid interest. The 2022 Notes were issued pursuant to, and are governed by an Indenture dated August 13, 2013, between the Company and U.S. Bank National Association, as trustee and the Company's subsidiaries named therein as guarantors (the Indenture). The Indenture contains affirmative and negative covenants that, among other things, limit the ability of the Company and its subsidiaries that guarantee the 2022 Notes to incur indebtedness; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; refinance certain indebtedness; merge with or into other companies or transfer substantially all of their assets; and, in certain circumstances, to pay dividends or make other distributions on stock.

8.875% Senior Notes

On November 6, 2012, the Company completed a private offering to eligible purchasers of an aggregate principal amount of $750.0 million of its 8.875% senior notes due 2021 (the 2021 Notes), issued at 99.247% of par. The net proceeds from the offering were approximately $725.6 million after deducting the initial purchasers' discounts, commissions and offering expenses and were used to fund a portion of the cash consideration paid in the Williston Basin Assets acquisition.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT (Continued)

On January 14, 2013, the Company issued an additional $600.0 million aggregate principal amount of the 2021 Notes at a price to the initial purchasers of 105% of par. The net proceeds from the sale of the additional 2021 Notes of approximately $619.5 million (after the initial purchasers' premiums, commissions and offering expenses) were used to repay all of the then outstanding borrowings under the Senior Credit Agreement and for general corporate purposes, including funding a portion of the Company's 2013 capital expenditures program. These notes were issued as "additional notes" under the indenture governing the 2021 Notes and under the indenture are treated as a single series with substantially identical terms as the 2021 Notes previously issued.

The 2021 Notes bear interest at a rate of 8.875% per annum, payable semi-annually on May 15 and November 15 of each year, beginning on May 15, 2013. The Notes will mature on May 15, 2021. The 2021 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2021 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's existing wholly-owned subsidiaries. Halcón, the issuer of the 2021 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On June 4, 2013, the Company completed a registered exchange offer of outstanding 2021 Notes for new registered notes having terms substantially identical to the 2021 Notes.

On or before November 15, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 2021 Notes with the net cash proceeds of certain equity offerings at a redemption price of 108.875% of the principal amount plus accrued and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2021 Notes originally issued remains outstanding immediately after the redemption and the redemption occurs within 180 days of the date of closing of the related equity offering. In addition, at any time prior to November 15, 2016, the Company may redeem some or all of the 2021 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess , if any of (a) the present value at such time of (i) the redemption price of such note at November 15, 2016, plus (ii) any required interest payments due on the notes through November 15, 2016 (excluding currently accrued and unpaid interest) computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

On or after November 15, 2016, the Company may redeem some or all of the 2021 Notes at any time or from time to time at the redemption prices (expressed as percentages of the principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning November 15 of the years indicated below:

Year	Percentage
2016	104.438%
2017	102.219%
2018 and thereafter	100.000%

In addition, upon a change of control of the Company, holders of the 2021 Notes will have the right to require the Company to repurchase all or any part of their Notes for cash at a price equal to 101% of the aggregate principal amount of the Notes repurchased, plus any accrued and unpaid interest. The 2021 Notes were issued under and governed by an Indenture dated November 6, 2012,

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT (Continued)

between the Company, U.S. Bank National Association, as trustee and the Company's subsidiaries named therein as guarantors (the Indenture). The Indenture contains covenants that, among other things, limit the ability of the Company and its subsidiaries to: incur indebtedness; pay dividends or make other distributions on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; refinance certain indebtedness; and merge with or into other companies or transfer substantially all of the Company's assets.

In conjunction with the issuance of the 2021 Notes, the Company recorded a discount of approximately $5.7 million to be amortized over the remaining life of the 2021 Notes using the effective interest method. The remaining unamortized discount was $5.1 million at December 31, 2013. In conjunction with the issuance of the additional 2021 Notes, the Company recorded a premium of approximately $30.0 million to be amortized over the remaining life of the additional 2021 Notes using the effective interest method. The remaining unamortized premium was $27.5 million at December 31, 2013.

9.75% Senior Notes

On July 16, 2012, the Company completed a private offering of $750.0 million aggregate principal amount of 9.75% senior notes due 2020 issued at 98.646% of par (the 2020 Notes). The net proceeds from the offering were approximately $723.1 million after deducting the initial purchasers' discounts, commissions and offering expenses and were used to fund a portion of the cash consideration paid in the Merger and the East Texas Assets acquisition.

On December 19, 2013, the Company issued an additional $400.0 million aggregate principal amount of the 2020 Notes at a price to the initial purchasers of 102.750% of par. The net proceeds from the sale of the additional 2020 Notes of approximately $406.1 million (after the initial purchasers' fees, commissions and offering expenses) were used to repay a portion of the then outstanding borrowings under the Senior Credit Agreement. These notes were issued as "additional notes" under the indenture governing the 2020 Notes and under the indenture are treated as a single series with substantially identical terms as the 2020 Notes previously issued. The borrowing base under the Company's Senior Credit Agreement was reduced by $100.0 million as a result of the issuance of the additional 2020 Notes.

The 2020 Notes bear interest at a rate of 9.75% per annum, payable semi-annually on January 15 and July 15 of each year, beginning on January 15, 2013. The 2020 Notes will mature on July 15, 2020. The 2020 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2020 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's existing wholly-owned subsidiaries. Halcón, the issuer of the 2020 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On June 4, 2013, the Company completed a registered exchange offer of outstanding 2020 Notes for new registered notes having terms substantially identical to the 2020 Notes.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT (Continued)

On or before July 15, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 2020 Notes with the net cash proceeds of certain equity offerings at a redemption price of 109.750% of the principal amount plus accrued and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2020 Notes originally issued remains outstanding immediately after the redemption and the redemption occurs within 180 days of the equity offering. In addition, at any time prior to July 15, 2016, the Company may redeem some or all of the 2020 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at July 15, 2016, plus (ii) any required interest payments due on the notes through July 15, 2016 (excluding currently accrued and unpaid interest) computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

On or after July 15, 2016, the Company may redeem some or all of the 2020 Notes at any time or from time to time at the redemption prices (expressed as percentages of the principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning July 15 of the years indicated below:

Year	Percentage
2016	104.875%
2017	102.438%
2018 and thereafter	100.000%

In addition, upon a change of control of the Company, holders of the 2020 Notes will have the right to require the Company to repurchase all or any part of their notes for cash at a price equal to 101% of the aggregate principal amount of the notes repurchased, plus any accrued and unpaid interest. The 2020 Notes were issued under and governed by an Indenture dated July 16, 2012, between the Company, U.S. Bank National Association, as trustee and the Company's subsidiaries named therein as guarantors (the Indenture). The Indenture contains covenants that, among other things, limit the ability of the Company and its subsidiaries to: incur indebtedness; pay dividends or make other distributions on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; refinance certain indebtedness; and merge with or into other companies or transfer substantially all of the Company's assets.

In conjunction with the issuance of the 2020 Notes, the Company recorded a discount of approximately $10.2 million to be amortized over the remaining life of the 2020 Notes using the effective interest method. The remaining unamortized discount was $8.9 million at December 31, 2013. In conjunction with the issuance of the additional 2020 Notes, the Company recorded a premium of approximately $11.0 million to be amortized over the remaining life of the additional 2020 Notes using the effective interest method. The remaining unamortized premium was approximately $11.0 million at December 31, 2013.

8.0% Convertible Note

On February 8, 2012, the Company issued the 2017 Note in the principal amount of $275.0 million together with the February 2012 Warrants for an aggregate purchase price of $275.0 million. The 2017 Note bears interest at a rate of 8% per annum, payable quarterly on March 31, June 30, September 30

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT (Continued)

and December 31 of each year and matures on February 8, 2017. Through the March 31, 2014 interest payment date, the Company may elect to pay the interest in kind, by adding to the principal of the 2017 Note, all or any portion of the interest due on the 2017 Note. The Company elected to pay the interest in kind on March 31, June 30 and September 30, 2012, and rolled $3.2 million, $5.7 million and $5.8 million of interest incurred during the first, second and third quarters of 2012, respectively, into the 2017 Note, increasing the principal amount to $289.7 million. The Company did not elect to pay-in-kind interest for the quarterly payments due subsequent to September 30, 2012. As of February 8, 2014, the note can be converted into common stock. Each $4.50 of principal and accrued but unpaid interest is convertible into one share of the Company's common stock. The 2017 Note is a senior unsecured obligation of the Company.

The Company allocated the proceeds received for the 2017 Note and February 2012 Warrants on a relative fair value basis. Consequently, the Company recorded a discount of $43.6 million to be amortized over the remaining life of the 2017 Note utilizing the effective interest rate method. The remaining unamortized discount was $30.3 million at December 31, 2013.

Promissory Notes

On December 28, 2012, the Company completed the acquisition of certain oil and natural gas properties in Brazos County, Texas for approximately $83.7 million, before and subject to, customary closing adjustments, consisting of approximately $8.4 million in cash and approximately $75.3 million in promissory notes due August 30, 2013. During the three months ended March 31, 2013, the Company completed its review of the properties and paid approximately $62.4 million during the period for properties deemed to have clear title and no defects. In addition, notice was given to the sellers of the Company's assertion of title and environmental defects amounting to $12.9 million for the remaining properties. During the three months ended September 30, 2013, the title and environmental defects were cured by the sellers and the Company paid the remaining portion of the purchase price. The promissory notes were classified as current at December 31, 2012.

In conjunction with the issuance of the promissory notes in December 2012, the Company recorded a discount of approximately $0.6 million to be amortized over the remaining life of the promissory notes using the effective interest method. The Company expensed the discount during the first quarter of 2013.

Debt Maturities

Aggregate maturities required on long-term debt at December 31, 2013 are due in future years as follows (in thousands, excluding discounts, premiums and deferred premiums on derivative contracts):

2014	$	
2015		
2016		
2017		289,669
2018		
Thereafter		2,900,000
Total	$	3,189,669

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. LONG-TERM DEBT (Continued)

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt and amortizes such costs over the lives of the respective debt. During 2013, the Company capitalized approximately $23.8 million in costs associated with the issuance of the additional 2020 Notes, the 2022 Notes, the additional 2021 Notes and costs incurred for amendments to the Company's Senior Credit Agreement. The Company expensed $3.4 million of debt issuance costs in conjunction with decreases in the Company's borrowing base under the Senior Credit Agreement. At December 31, 2013 and December 31, 2012, the Company had approximately $64.3 million and $51.6 million, respectively, of debt issuance costs remaining that are being amortized over the lives of the respective debt.

7. FAIR VALUE MEASUREMENTS

Pursuant to ASC 820, the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 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 (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2013 and 2012. As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for the year ended December 31, 2013.

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets				
Receivables from derivative contracts	$	$ 24,762	$	$ 24,762
Liabilities				
Liabilities from derivative contracts	$	$ 34,376	$ 2,816	$ 37,192

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. FAIR VALUE MEASUREMENTS (Continued)

	December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets				
Receivables from derivative contracts	$	$ 7,799	$	$ 7,799
Liabilities				
Liabilities from derivative contracts	$	$ 12,890	$	$ 12,890
Liabilities from warrants[(1)]		1,342		1,342
Total Liabilities	$	$ 14,232	$	$ 14,232

(1)
Liabilities from the August 2012 warrants are recorded in *"Accounts payable and accrued liabilities"* on the consolidated balance sheet at December 31, 2012.

Derivative contracts listed above as Level 2 include collars, swaps and put options that are carried at fair value. The Company records the net change in the fair value of these positions in *"Net gain (loss) on derivative contracts"* in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. See Note 8, *"Derivative and Hedging Activities"* for additional discussion of derivatives.

Derivative contracts listed above as Level 3 include extendable collars entered into during 2013 that are carried at fair value. The significant unobservable inputs for these Level 3 contracts include unpublished forward strip prices and market volatilities. The following table sets forth a reconciliation of changes in the fair value of the Company's extendable collar contracts classified as Level 3 in the fair value hierarchy (in thousands):

	Significant Unobservable Inputs (Level 3)	
	December 31,	
	2013	2012
Beginning Balance	$	$
Net gain (loss) on derivative contracts	(2,816)	
Settlements		

Purchase of derivative contracts				
Buy out of derivative contracts				
Ending Balance	$	(2,816)	$	
Change in unrealized gains (losses) included in earnings related to derivatives still held as of December 31, 2013 and 2012	$	(2,816)	$	

As of December 31, 2013 and 2012, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. FAIR VALUE MEASUREMENTS (Continued)

the derivative contracts; however, the Company does not anticipate such nonperformance. Each of the counterparties to the Company's current derivative contracts is a lender or an affiliate of a lender in the Company's Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement.

Warrants listed above at December 31, 2012 were carried at fair value. The Company recorded the net change in fair value on the August 2012 Warrants in *"Interest expense and other, net"* in the Company's consolidated statements of operations. At December 31, 2012, the Company valued the August 2012 Warrants based on observable market data, including treasury rates, historical volatility and data for similar instruments which resulted in the Company reporting its warrants as Level 2. During 2013, the Company recorded a gain of $1.6 million for the expiration of the warrants. See Note 11, *"Preferred Stock and Stockholders' Equity"* for additional discussion on the terms of the warrants.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Senior Credit Agreement and the promissory notes approximates carrying value because the interest rates approximate current market rates. The following table presents the estimated fair values of the Company's fixed interest rate, long-term debt instruments as of December 31, 2013 and 2012 (excluding discounts and premiums):

Debt	December 31, 2013 Carrying Amount	December 31, 2013 Estimated Fair Value	December 31, 2012 Carrying Amount	December 31, 2012 Estimated Fair Value
	(In thousands)		(In thousands)	
9.25% $400 million senior notes	$ 400,000	$ 407,432	$	$
8.875% $1.35 billion senior notes	1,350,000	1,390,500	750,000	798,750
9.75% $1.15 billion senior notes	1,150,000	1,197,438	750,000	815,160
8.0% $275 million convertible note	289,669	368,418	289,669	625,425
	$ 3,189,669	$ 3,363,788	$ 1,789,669	$ 2,239,335

The fair value of the Company's fixed interest debt instruments was calculated using Level 2 criteria at December 31, 2013 and 2012. The fair value of the Company's senior notes is based on quoted market prices from trades of such debt. The fair value of the Company's convertible note is based on published market prices and risk-free rates.

During the year ended December 31, 2013, the Company recorded a non-cash impairment charge of $67.5 million related to its gas gathering systems. See Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of the valuation approach used and the classification of the estimate within the fair value hierarchy.

As of July 1, 2013, the Company performed its annual goodwill impairment test which involved the fair value estimation of the Company's reporting unit. See Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of the valuation approaches used and the classification of the estimate within the fair value hierarchy.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. FAIR VALUE MEASUREMENTS (Continued)

The Company follows the provisions of ASC 820, for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. These provisions apply to the Company's initial recognition of asset retirement obligations for which fair value is used. The asset retirement obligation estimates are derived from historical costs and management's expectation of future cost environments; and therefore, the Company has designated these liabilities as Level 3. See Note 9, *"Asset Retirement Obligations,"* for a reconciliation of the beginning and ending balances of the liability for the Company's asset retirement obligations.

Changes in Level 3 Instruments Measured at Fair Value on a Recurring Basis

At December 31, 2012, the Company transferred amounts from Level 3 to Level 2 for its 2020 Notes because inputs became more observable with the passage of time and the larger amount of trading activity which provides the quoted market prices. The following table provides a reconciliation of financial assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Carrying Amount (In thousands)
December 31, 2011	$
Transfer into Level 3	750,000
Transfer out of Level 3	(750,000)
December 31, 2012	$

The Company now believes it has readily determinable market prices which allow for the long-term debt to be properly measured and the long-term debt was reclassified from Level 3 to Level 2.

8. DERIVATIVE AND HEDGING ACTIVITIES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to economically hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. Derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. Historically, the Company has also entered into interest rate swaps to mitigate exposure to market rate fluctuations. The Company does not enter into derivative contracts for speculative trading purposes.

It is the Company's policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The counterparties to the Company's current derivative contracts are lenders or affiliates of lenders in its Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Company's Senior Credit Agreement.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

The Company's crude oil and natural gas derivative positions at any point in time may consist of swaps, swaptions, costless put/call "collars," extendable costless collars and put options. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. Swaptions are swap contracts that may be extended annually at the option of the counterparty on a designated date. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract and a purchased put that establishes a minimum price. Extendable collars are costless put/call contracts that may be extended annually at the option of the counterparty on a designated date. A sold put option limits the exposure of the counterparty's risk should the price fall below the strike price. Sold put options limit the effectiveness of purchased put options at the low end of the put/call collars to market prices in excess of the strike price of the put option sold. The Company has elected to not designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

In February 2012, pursuant to the Senior Credit Agreement, the Company novated its oil and natural gas derivative instruments to counterparties that are lenders within the Senior Credit Agreement resulting in a realized loss of $0.4 million for novation fees and terminated the interest rate derivatives resulting in a $0.6 million realized loss, both of which were included in "*Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

In April 2011, pursuant to the Company's March 2011 Credit Facilities, the Company was required to reduce the volume of its existing oil and natural gas derivative contracts so it would not exceed the maximum allowable volumes for future production periods and to novate derivative contracts to counterparties that are lenders within the March 2011 Credit Facilities. During the second quarter of 2011, the Company recognized a $0.9 million realized loss on the unwinding of the excess oil and natural gas derivative contracts and paid $0.5 million in fees to complete the novation, both of which were included in "*Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

At December 31, 2013, the Company had 86 open commodity derivative contracts summarized in the following tables: 10 natural gas collar arrangements, 52 crude oil collar arrangements, five crude oil three-way collars, one crude oil put option, eight crude oil swaps, eight crude oil swaptions and two crude oil extendable collars.

At December 31, 2012, the Company had 47 open commodity derivative contracts summarized in the tables below: two natural gas collar arrangements, two natural gas swaps, one natural gas basis swap, 28 crude oil collar arrangements, 10 crude oil three-way collars, and four crude oil swaps.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the consolidated balance sheets as assets or liabilities.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

The following table summarizes the location and fair value amounts of all derivative contracts in the consolidated balance sheets as of December 31, 2013 and 2012:

Derivatives not designated as hedging contracts under ASC 815	Balance sheet location	Asset derivative contracts December 31, 2013	Asset derivative contracts December 31, 2012	Balance sheet location	Liability derivative contracts December 31, 2013	Liability derivative contracts December 31, 2012
		(In thousands)			(In thousands)	
Commodity contracts	Current assets receivables from derivative contracts	$ 2,028	$ 7,428	Current liabilities liabilities from derivative contracts	$ (17,859)	$ (10,429)
Commodity contracts	Other noncurrent assets receivables from derivative contracts	22,734	371	Other noncurrent liabilities liabilities from derivative contracts	(19,333)	(2,461)
Total derivatives not designated as hedging contracts under ASC 815		$ 24,762	$ 7,799		$ (37,192)	$ (12,890)

The following table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations:

Derivatives not designated as hedging contracts under ASC 815	Location of gain or (loss) recognized in income on derivative contracts	Amount of gain or (loss) recognized in income on derivative contracts for the year ended December 31, 2013	2012	2011
		(In thousands)		
Commodity contracts:				
Unrealized gain (loss) on commodity contracts	Other income (expenses) net gain (loss) on derivative contracts	$ (10,150)	$ (13,723)	$ 5,269
Realized gain (loss) on commodity contracts	Other income (expenses) net gain (loss) on derivative contracts	(21,083)	7,655	(1,078)
Total net gain (loss) on commodity contracts		$ (31,233)	$ (6,068)	$ 4,191
Interest rate swaps:				
Unrealized gain (loss) on interest rate swaps	Other income (expenses) net gain (loss) on derivative contracts	$	$ 518	$ (506)
Realized gain (loss) on interest rate swaps	Other income (expenses) net gain (loss) on derivative contracts		(576)	(206)

Total net gain (loss) on interest rate swaps		$		$	(58)	$	(712)
Total net gain (loss) on derivative contracts	Other income (expenses) net gain (loss) on derivative contracts	$	(31,233)	$	(6,126)	$	3,479

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

At December 31, 2013 and 2012, the Company had the following open crude oil and natural gas derivative contracts:

			December 31, 2013						
				Floors		Ceilings		Put Options Sold	
Period	**Instrument**	**Commodity**	**Volume in Mmbtu's/ Bbl's**	**Price / Price Range**	**Weighted Average Price**	**Price / Price Range**	**Weighted Average Price**	**Price / Price Range**	**Weighted Average Price**
January 2014 - March 2014	Three-Way Collars	Crude Oil	144,000	$ 95.00	$ 95.00	$ 98.60 - 109.50	$ 100.03	$ 70.00	$ 70.00
January 2014 - June 2014	Collars	Crude Oil	724,000	90.00	90.00	96.50 - 99.50	98.00		
January 2014 - December 2014	Collars	Crude Oil	7,573,750	85.00 - 95.00	88.67	93.60 - 108.45	96.22		
January 2014 - December 2014	Collars	Natural Gas	11,862,500	3.75 - 4.00	3.85	4.26 - 4.55	4.35		
April 2014 - June 2014	Three-Way Collars	Crude Oil	136,500	95.00	95.00	98.20 - 101.00	99.13	70.00	70.00
July 2014 - December 2014	Collars	Crude Oil	920,000	87.50 - 90.00	89.50	92.50 - 100.25	97.87		
July 2014 - December 2014	Collars	Natural Gas	920,000	4.00	4.00	4.42	4.42		
July 2014 - December 2014	Put	Crude Oil	184,000					90.00	90.00
January 2015 - June 2015	Collars	Crude Oil	1,583,750	85.00 - 90.00	86.29	91.00 - 98.50	93.14		
January 2015 - December 2015*(1)*	Collars	Crude Oil	5,110,000	82.50 - 90.00	86.07	90.00 - 100.25	94.65		
January 2015 - December 2015	Collars	Natural Gas	6,387,500	4.00	4.00	4.55 - 4.85	4.68		
January 2015 - December 2015*(2)*	Swaps	Crude Oil	1,095,000	91.00 - 91.25	91.17				
January 2016 - December 2016*(3)*	Swaps	Crude Oil	2,190,000	88.00 - 88.87	88.30				

(1) Includes an outstanding crude oil collar of 730,000 Bbls which may be extended at a floor of $85.00 per Bbl and a ceiling of $96.20 per Bbl for the year ended December 31, 2016. Also includes an outstanding crude oil collar of 365,000 Bbls which may be extended at a floor of $85.00 per Bbl and a ceiling of $96.00 per Bbl for the year ended December 31, 2016.

(2) Includes an outstanding crude oil swap of 730,000 Bbls which may be extended at a price of $91.25 per Bbl for the year ended December 31, 2016. Also includes certain outstanding crude oil swaps totaling 365,000 Bbls which may be extended at a price of $91.00 per Bbl for the year ended December 31, 2016.

(3) Includes an outstanding crude oil swap of 730,000 Bbls which may be extended at a price of $88.25 per Bbl for the year ended December 31, 2017. Also includes certain outstanding crude oil swaps totaling 912,500 Bbls which may be extended at a price of $88.00 per Bbl for the year ended December 31, 2017. Includes an outstanding crude oil swap of 547,500 Bbls which may be extended at a price of $88.87 per Bbl for the year ended December 31, 2017.

			December 31, 2012						
				Floors		Ceilings		Put Options Sold	
Period	**Instrument**	**Commodity**	**Volume in Mmbtu's/ Bbl's**	**Price / Price Range**	**Weighted Average Price**	**Price / Price Range**	**Weighted Average Price**	**Price / Price Range**	**Weighted Average Price**

January 2013 - March 2013	Three-Way Collars	Crude Oil	130,500	$ 95.00 - 100.00	$ 95.34	$ 105.50 - 109.50	$ 101.36	$ 70.00	$ 70.00
January 2013 - March 2013	Basis Swap	Natural Gas	225,000						
January 2013 - March 2013	Collars	Crude Oil	31,500	95.00	95.00	101.50	101.50		
January 2013 - March 2013	Swap	Natural Gas	225,000	4.85	4.85				
April 2013 - June 2013	Three-Way Collars	Crude Oil	120,575	95.00	95.00	99.50 - 100.60	99.77	70.00	70.00
April 2013 - June 2013	Collars	Crude Oil	29,575	95.00	95.00	100.60	100.60		
July 2013 - September 2013	Collars	Crude Oil	147,200	95.00	95.00	99.00 - 101.50	99.94		
October 2013 - December 2013	Collars	Crude Oil	142,600	95.00	95.00	99.00 - 101.00	99.71		
January 2013 - December 2013	Collars	Crude Oil	5,201,250	80.00 - 100.00	89.04	91.65 - 107.25	98.06		
January 2013 - December 2013	Collars	Natural Gas	1,825,000	3.75	3.75	4.26	4.26		
January 2013 - December 2013	Swap	Natural Gas	240,000	3.56	3.56				
January 2013 - December 2013	Swap	Crude Oil	360,000	97.60 - 105.55	102.18				
February 2013 - December 2013	Collars	Crude Oil	250,500	100.00	100.00	104.15	104.15		
April 2014 - June 2014	Three-Way Collars	Crude Oil	136,500	95.00	95.00	98.20 - 101.00	99.13	70.00	70.00
January 2014 - March 2014	Three-Way Collars	Crude Oil	144,000	95.00	95.00	98.60 - 109.50	100.03	70.00	70.00
January 2014 - December 2014	Collars	Crude Oil	2,190,000	85.00	85.00	95.10 - 96.35	95.92		
January 2014 - December 2014	Collars	Natural Gas	1,825,000	3.75	3.75	4.26	4.26		

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

The Company's interest rate derivative positions at December 31, 2011, consisting of interest rate swaps, are shown in the following table.

Interest Rate Swaps(1)(3)

Year	Notional Amount (in thousands)	Fixed Rate	Counterparty Floating Rate(2)	Months Covered
2012	$ 50,000	2.51%	3 Month LIBOR	January - December
2013	50,000	2.51%	3 Month LIBOR	January - December
2014	50,000	2.51%	3 Month LIBOR	January - March

(1) Settlement is paid to the Company if the counterparty floating exceeds the fixed rate and settlement is paid by the Company if the counterparty floating rate is below the fixed rate. Settlement is calculated as the difference in the fixed rate and the counterparty rate.

(2) Subject to minimum rate of 2%.

(3) All outstanding interest rate swaps were terminated in conjunction with the recapitalization during February 2012.

The Company presents the fair value of its derivative contracts at the gross amounts in the consolidated balance sheets. The following table shows the potential effects of master netting arrangements on the fair value of the Company's derivative contracts at December 31, 2013 and 2012 in accordance with ASU 2011-11 and ASU 2013-01, which were effective beginning January 1, 2013:

	Derivative Assets		Derivative Liabilities	
	December 31,		December 31,	
Offsetting of Derivative Assets and Liabilities	**2013**	**2012**	**2013**	**2012**
	(In thousands)		(In thousands)	
Gross amounts presented in the consolidated balance sheets	$ 24,762	$ 7,799	$ (37,192)	$ (12,890)
Amounts not offset in the consolidated balance sheets	(20,036)	(4,118)	19,507	3,899
Net amount	$ 4,726	$ 3,681	$ (17,685)	$ (8,991)

The Company enters into an International Swap Dealers Association Master Agreement (ISDA) with each counterparty prior to a derivative contract with such counterparty. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

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9. ASSET RETIREMENT OBLIGATIONS

The Company records an asset retirement obligation (ARO) when it can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. For gas gathering systems and equipment, the Company records an ARO when the system is placed in service and it can reasonably estimate the fair value of an obligation to perform site reclamation and other necessary work when it is required. The Company records the ARO liability on the consolidated balance sheets and capitalizes a portion of the cost in *"Oil and natural gas properties"* or *"Other operating property and equipment"* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and accretion"* expense in the consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis or straight-line basis.

The Company recorded the following activity related to its ARO liability for the years ended December 31, 2013 and 2012 (in thousands, inclusive of the current portion):

Liability for asset retirement obligation as of December 31, 2011	$ 33,713
Liabilities settled and divested[(1)]	(4,213)
Additions	2,627
Acquisitions[(1)]	33,855
Accretion expense	2,306
Revisions in estimated cash flows	6,844
Liability for asset retirement obligation as of December 31, 2012	$ 75,132
Liabilities settled and divested[(1)]	(55,905)
Additions	11,730
Acquisitions[(1)]	4,236
Accretion expense	3,596
Revisions in estimated cash flows	468
Liability for asset retirement obligation as of December 31, 2013	$ 39,257

(1) See Note 4, *"Acquisitions and Divestitures"* for additional information on the Company's acquisition and divestiture activities.

10. COMMITMENTS AND CONTINGENCIES

Commitments

The Company leases corporate office space in Houston, Texas; Tulsa, Oklahoma; and Denver, Colorado as well as a number of other field office locations. In addition, the Company has lease commitments for certain equipment under long-term operating lease agreements. The office and equipment operating lease agreements expire on various dates through 2024. Rent expense was approximately $8.7 million, $3.7 million and $1.3 million for the years ended December 31, 2013, 2012

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. COMMITMENTS AND CONTINGENCIES (Continued)

and 2011, respectively. Approximate future minimum lease payments for subsequent annual periods for all non-cancelable operating leases as of December 31, 2013 are as follows (in thousands):

2014	$ 8,540
2015	9,062
2016	8,855
2017	9,047
2018	9,299
Thereafter	23,828
Total	$ 68,631

As of December 31, 2013, the Company has drilling rig commitments as follows (in thousands):

2014	$ 37,672
2015	11,275
2016	
2017	
2018	
Thereafter	
Total	$ 48,947

As of December 31, 2013, early termination of the drilling rigs commitments would require termination penalties of $30.2 million, which would be in lieu of paying the remaining drilling commitments of $48.9 million.

The Company has various other contractual commitments for, among other things, pipeline and well equipment, seismic, and infrastructure related expenditures.

2014	$ 15,388
2015	
2016	
2017	
2018	
Thereafter	
Total	$ 15,388

The Company has entered into various long-term gathering, transportation and sales contracts in its Bakken / Three Forks formations in North Dakota which are not included in the tables above. As of December 31, 2013, the Company had in place nine long-term crude oil contracts and two long-term natural gas contracts in this area. Under the terms of these contracts, the Company has committed a substantial portion of its Bakken / Three Forks production for periods ranging from five to ten years from the date of first production. The sales prices under these contracts are based on posted market rates. The Company believes that there are sufficient available reserves and supplies in the Bakken / Three Forks formations to meet its commitments, as the proved reserves from this area represent approximately 67% of its total proved reserves.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. COMMITMENTS AND CONTINGENCIES (Continued)

Additionally, as of December 31, 2013, the Company had one long-term natural gas transportation contract and one long-term natural gas gathering contract in the Woodbine formation in East Texas which are not included in the tables above. The rate under the transportation contract was negotiated based on market rates and the contract term is five years from the date of first production. Under the gathering contract, the Company has committed substantially all of its natural gas production from specific wells in the area, until a contracted volume amount is reached, in exchange for the construction of a gathering system. The contract term is five years from the date of first production.

Historically, the Company has been able to meet its delivery commitments.

Contingencies

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. While the outcome and impact of currently pending legal proceedings cannot be determined, the Company's management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material effect on the Company's consolidated operating results, financial position or cash flows.

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY

Preferred Stock and Non-Cash Preferred Stock Dividend

On February 29, 2012 (the Commitment Date), the Company entered into definitive agreements with a group of certain institutional and selected other accredited investors (collectively, the investors) to sell, in a private offering, 4,444.4511 shares of 8% Automatically Convertible Preferred Stock, par value $0.0001 per share (the Preferred Stock), each share of which was convertible into 10,000 shares of common stock. Also on February 29, 2012, the Company received an executed written consent (the Consent) in lieu of a stockholders' meeting authorizing and approving the conversion of the Preferred Stock into common stock. On March 2, 2012, the Company filed a Certificate of Designation, Preferences, Rights and Limitations of the Preferred Stock (the Certificate of Designation) with the Delaware Secretary of State which stated the conversion was to occur on the twentieth day after the mailing of a definitive information statement to stockholders. On March 5, 2012, the Company issued the Preferred Stock to the investors at $90,000 per share. Gross proceeds from the offering were approximately $400.0 million, or $9.00 per share of common stock, before offering expenses. The Company incurred placement agent fees of $14.0 million and associated expenses of approximately $0.5 million in connection with this offering. On March 28, 2012, the Company mailed a definitive information statement to its common stockholders notifying them that Halcón's majority stockholder had consented to the issuance of common stock, par value $0.0001, upon the conversion of the Preferred Stock. The Preferred Stock automatically converted into 44.4 million shares of common stock on April 17, 2012 in accordance with the terms of the Certificate of Designation. No cash dividends were paid on the Preferred Stock since pursuant to the terms of the Certificate of Designation of the Preferred Stock, conversion occurred prior to May 31, 2012. On November 30, 2012, the Company filed a Certificate of Elimination with the Delaware Secretary of State eliminating all provisions of the Certificate of Designation of the Preferred Stock.

In accordance with ASC 470, *Debt* (ASC 470), the Company determined that the conversion feature in the Preferred Stock represented a beneficial conversion feature. The fair value of the common stock of $10.99 per share on the Commitment Date was greater than the conversion price of

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

$9.00 per share of common stock, representing a beneficial conversion feature of $1.99 per share of common stock, or $88.4 million in aggregate. Under ASC 470, $88.4 million (the intrinsic value of the beneficial conversion feature) of the proceeds received from the issuance of the Preferred Stock was allocated to additional paid-in capital, creating a discount on the Preferred Stock (the Discount). The Discount resulting from the allocation of value to the beneficial conversion feature was required to be amortized on a non-cash basis over the approximate 71-month period between the issuance date and the required redemption date of February 9, 2018, or fully amortized upon an accelerated date of redemption or conversion, and recorded as a preferred dividend. As a result, approximately $1.1 million of the Discount was amortized and a non-cash preferred dividend was recorded in the first quarter of 2012 and due to the conversion date occurring on April 17, 2012, the remaining $87.3 million of Discount amortization was accelerated to the conversion date and was fully amortized in the second quarter of 2012 as per the guidance of ASC 470. The Discount amortization is reflected as non-cash preferred dividend in the consolidated statements of operations. In accordance with the guidance in ASC 480, the preferred dividend was charged against additional paid-in capital since no retained earnings were available.

On December 6, 2012, the Company completed the Williston Basin Acquisition for a total adjusted purchase price of approximately $1.5 billion, consisting of approximately $788.8 million in cash and approximately $695.2 million in newly issued shares of Halcón preferred stock that automatically converted into 108.8 million shares of Halcón common stock (equivalent to a conversion price of approximately $7.45 per share of Halcón common stock), following stockholder approval on January 17, 2013 of such conversion and an amendment to Halcón's certificate of incorporation to increase the number of shares of common stock that Halcón is authorized to issue. The shares of preferred stock were issued to the Petro-Hunt Parties in a private placement pursuant to the exemptions from registration under Section 4(2) of the Securities Act of 1933, as amended.

On January 17, 2013, the Company received the results from the special stockholders' meeting authorizing and approving the issuance of 108.8 million shares of common stock upon the conversion of the convertible preferred stock issued to the Petro-Hunt Parties. Following the approval by the stockholders, on January 18, 2013, each outstanding share of the Company's preferred stock converted into 10,000 shares of its common stock at an effective conversion price of approximately $7.45 per share. No proceeds were received by the Company upon conversion of the preferred stock. No cash dividends were paid on the preferred stock since pursuant to the terms of the Certificate of Designation of the preferred stock, conversion occurred prior to April 6, 2013. On June 13, 2013, the Company filed a Certificate of Elimination with the Delaware Secretary of State eliminating all provisions of the Certificate of Designation.

5.75% Series A Convertible Perpetual Preferred Stock

On June 18, 2013, the Company completed its offering of 345,000 shares of its 5.75% Series A Convertible Perpetual Preferred Stock (the Series A Preferred Stock) at a public offering price of $1,000 per share (the Liquidation Preference). The Company filed a Certificate of Designations, Preferences, Rights and Limitations of 5.75% Series A Convertible Preferred Stock on June 17, 2013 (the Series A Designation). The net proceeds to the Company from the offering of the Series A Preferred Stock were approximately $335.5 million, after deducting the underwriting discount and offering expenses. The Company used the net proceeds from the offering to repay a portion of the outstanding borrowings under its Senior Credit Agreement.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by the Company's Board of Directors, cumulative dividends at the rate of 5.75% per annum (the dividend rate) on the Liquidation Preference per share of the Series A Preferred Stock, payable quarterly in arrears on each dividend payment date. Dividends may be paid in cash or, where freely transferable by any non-affiliate recipient thereof, in common stock of the Company or a combination thereof, and are payable on March 1, June 1, September 1 and December 1 of each year, commencing on September 1, 2013. During the year ended December 31, 2013, the Company paid cumulative, declared dividends of $9.1 million by issuing approximately 2.0 million shares of common stock reflected as a non-cash dividend. As of December 31, 2013, cumulative, undeclared dividends on the Series A Preferred Stock amounted to approximately $1.7 million.

The Series A Preferred Stock has no maturity date, is not redeemable by the Company at any time, and will remain outstanding unless converted by the holders or mandatorily converted by the Company as described below.

Each share of Series A Preferred Stock is convertible, at the holder's option at any time, initially into approximately 162.4431 shares of common stock of the Company (which is equivalent to an initial conversion price of approximately $6.16 per share), subject to specified adjustments as set forth in the Series A Designation. Based on the initial conversion rate, approximately 56.0 million shares of common stock of the Company would be issuable upon conversion of all the shares of Series A Preferred Stock.

On or after June 6, 2018, the Company may, at its option, give notice of its election to cause all outstanding shares of the Series A Preferred Stock to be automatically converted into shares of common stock of the Company at the conversion rate (as defined in the Series A Designation), if the closing sale price of the Company's common stock equals or exceeds 150% of the conversion price for at least 20 trading days in a period of 30 consecutive trading days.

If the Company undergoes a fundamental change (as defined in the Series A Designation) and a holder converts its shares of the Series A Preferred Stock at any time beginning at the opening of business on the trading day immediately following the effective date of such fundamental change and ending at the close of business on the 30th trading day immediately following such effective date, the holder will receive, for each share of the Series A Preferred Stock surrendered for conversion, a number of shares of common stock of the Company equal to the greater of: (1) the sum of (i) the conversion rate and (ii) the make-whole premium, if any, as described in the Series A Designation; and (2) the conversion rate which will be increased to equal (i) the sum of the $1,000 liquidation preference plus all accumulated and unpaid dividends to, but excluding, the settlement date for such conversion, divided by (ii) the average of the closing sale prices of the Company's common stock for the five consecutive trading days ending on the third business day prior to such settlement date; provided that the prevailing conversion rate as adjusted pursuant to this will not exceed 292.3977 shares of common stock of the Company per share of the Series A Preferred Stock (subject to adjustment in the same manner as the conversion rate).

Except as required by Delaware law, holders of the Series A Preferred Stock will have no voting rights unless dividends are in arrears and unpaid for six or more quarterly periods. Until such arrearage is paid in full, the holders (voting as a single class with the holders of any other preferred shares having similar voting rights) will be entitled to elect two additional directors and the number of directors on the Company's board of directors will increase by that same number.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

Common Stock

On August 13, 2013, the Company completed the issuance and sale of 43.7 million shares of its common stock in an underwritten public offering. The shares of common stock sold have been registered under the Securities Act pursuant to a Registration Statement on Form S-3 (No. 333-188640), which was filed with the SEC and became automatically effective on May 16, 2013. The net proceeds to the Company from the offering of common stock were approximately $215.2 million, after deducting the underwriting discount and estimated offering expenses. The Company used the net proceeds from the offering to repay a portion of the then outstanding borrowings under its Senior Credit Agreement.

On January 17, 2013, with stockholder approval, the Company filed a Certificate of Amendment of the Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to increase its authorized common stock by approximately 333.3 million shares for a total of 670.0 million authorized shares of common stock.

On December 6, 2012, the Company completed the private placement of 41.9 million shares of common stock, par value $0.0001 per share, to CPP Investment Board PMI-2 Inc. (CPPIB), for gross proceeds of approximately $300.0 million, or $7.16 per share of common stock (the CPPIB Transaction). The net proceeds to the Company were $294.0 million following the payment of a $6.0 million capital commitment payment to CPPIB upon closing of the transaction. The shares of Halcón common stock were issued to CPPIB in a private placement pursuant to the exemptions from registration provided under Section 4(2) of the Securities Act. On September 27, 2013, the Company filed a shelf registration statement providing for the resale of certain of the shares of the Company's common stock held by CPPIB and its affiliates.

In early August 2012, in connection with the Merger and the East Texas Acquisition, the Company issued 51.3 million and 20.8 million shares of common stock, respectively. The shares were issued at closing of the transactions as a portion of the consideration of the purchase price. See Note 4, "*Acquisitions and Divestitures*," for additional discussion on the issuance of common stock in connection with these transactions.

On February 8, 2012, pursuant to the closing of the Recapitalization described in Note 2, "*Recapitalization*," the Company issued 73.3 million shares of the Company's common stock for a purchase price of $275.0 million. Costs incurred of $4.0 million were netted against the proceeds of the common stock and recorded accordingly. In addition, the Company amended its certificate of incorporation to increase the Company's authorized shares of common stock from 33.3 million shares to 336.7 million shares.

Warrants

In February 2012, in conjunction with the issuance of the 2017 Notes, the Company issued the February 2012 Warrants to purchase 36.7 million shares of the Company's common stock at an exercise price of $4.50 per share of common stock pursuant to the Recapitalization described in Note 2, "*Recapitalization.*" The Company allocated $43.6 million to the February 2012 Warrants which is reflected in additional paid-in capital in stockholders' equity, net of $0.6 million in issuance costs. The February 2012 Warrants entitle the holders to exercise the warrants in whole or in part at any time prior to the expiration date of February 8, 2017.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

In August 2012, as part of the Merger, the Company assumed outstanding GeoResources stock warrants. At the date of the Merger 0.6 million warrants were outstanding and converted to 1.2 million Halcón warrants (the August 2012 Warrants). Each GeoResources warrant was converted into an August 2012 Warrant to acquire one share of Halcón common stock (Share Portion) at an exercise price of $8.40 per share of common stock and the right to receive $20 in cash per equivalent assumed share (Cash Portion) at an exercise price of $0.82 per $1.00 received. The August 2012 Warrants contain substantially the same terms of the original GeoResources warrants with adjustments to the exercise price and addition of the Cash Portion to reflect the impact of the consideration per share from the Merger. These adjustments convert the terms to fundamentally equal what the warrant holders would have received had the warrants been exercised immediately prior to the close of the Merger. Under the terms of the August 2012 Warrants, the warrant holder must exercise the Share Portion and the Cash Portion in tandem. The August 2012 Warrants expired on June 9, 2013. The August 2012 Warrants were reflected as a current liability in the consolidated balance sheets at December 31, 2012 and were recorded at fair value. During 2013, the Company recorded a gain of $1.6 million for the expiration of the warrants. Changes in fair value and the gain upon expiration were recognized in "*Interest expense and other, net*" in the consolidated statements of operations.

Incentive Plan

On May 8, 2006, the Company's stockholders first approved its 2006 Long-Term Incentive Plan (the Plan). The Company reserved a maximum of 0.8 million shares of its common stock for issuances under the Plan. On May 8, 2008, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 0.8 million to 2.0 million. On May 3, 2010, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 2.0 million to 2.5 million. On February 8, 2012, as part of the Recapitalization described in Note 2, "*Recapitalization*," the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 2.5 million to 3.7 million. On May 17, 2012, shareholders approved an amendment and restatement of the Plan to (i) increase the maximum number of shares to be issued under the Plan from 3.7 million to 11.5 million; (ii) extend the effectiveness of the Plan for ten years from the date of approval; and (iii) amend various other provisions of the Plan. On May 23, 2013 shareholders approved an increase in authorized shares under the Plan from 11.5 million to 41.5 million. As of December 31, 2013 and 2012, a maximum of 25.7 million and 4.4 million shares of common stock, respectively, remained reserved for issuance under the Plan.

The Company accounts for share-based payment accruals under authoritative guidance on stock compensation, as set forth in ASC Topic 718. The guidance requires all share-based payments to employees and directors, including grants of stock options and restricted stock, to be recognized in the financial statements based on their fair values.

For the years ended December 31, 2013, 2012 and 2011, respectively, the Company recognized $17.1 million, $6.7 million, and $3.6 million, respectively, of share-based compensation expense as a component of "*General and administrative*" on the consolidated statements of operations.

Stock Options

During the year ended December 31, 2013, the Company granted stock options under the Plan covering 6.2 million shares of common stock to employees of the Company. Stock options, when

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

exercised, are settled through the payment of the exercise price in exchange for new shares of stock underlying the option. The stock options have exercise prices ranging from $4.43 per share of common stock to $8.23 per share of common stock with a weighted average exercise price of $7.07 per share of common stock. The weighted average grant date fair value of options granted in 2013 and 2012 was $16.4 million and $16.5 million, respectively. These awards typically vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date. At December 31, 2013 and 2012, the unrecognized compensation expense related to stock options totaled $13.7 million and $12.9 million, respectively, and will be recognized on the graded-vesting method over the requisite service periods. The weighted average remaining vesting period as of December 31, 2013 and 2012 was 1.2 years and 1.7 years, respectively.

The following table sets forth the stock option transactions for the years ended December 31, 2013, 2012 and 2011:

	Number	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value[(1)] (In thousands)	Weighted Average Remaining Contractual Life (Years)
Outstanding at December 31, 2010		$	$	
Granted				
Exercised				
Forfeited				
Outstanding at December 31, 2011		$	$	
Granted	4,847,333	7.24		
Exercised				
Forfeited	(35,500)	9.35		
Outstanding at December 31, 2012	4,811,833	$ 7.22	$ 2,944	9.7
Granted	6,171,000	7.07		
Exercised				
Forfeited	(566,588)	6.80		
Outstanding at December 31, 2013	10,416,245	$ 7.15	$	9.0

(1) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. No stock options were exercised during the years ended December 31, 2013 and 2012.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

Options outstanding at December 31, 2013 consisted of the following:

	Outstanding			Exercisable[(1)]			
Range of Grant Prices Per Share	Number	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Live (Years)	Number	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value	Weighted Average Remaining Contractual Live (Years)
$4.43 - $5.48	1,745,600	$ 5.46	8.9		$	$	
$5.54 - $7.09	1,446,800	6.59	8.9				
$7.10	5,309,300	7.10	9.2				
$7.16 - $11.55	1,914,545	9.27	8.5				

(1) At December 31, 2013, none of the Company's options were exercisable due to service performance conditions or option exercise prices below the current market value of the underlying stock as of December 31, 2013.

The assumptions used in calculating the fair value of the Company's share-based compensation for the years ended December 31, 2013 and 2012 are disclosed in the following table:

	Years Ended December 31, 2013	Years Ended December 31, 2012
Weighted average value per option granted during the period	$ 2.65	$ 3.40
Assumptions:		
Stock price volatility[(1)]	57.31%	61.84%
Risk free rate of return	0.89%	0.54%
Expected term	5 years	4 years

(1) Due to the Company's limited historical data, expected volatility was estimated using volatilities of similar entities whose share or options prices and assumptions are publicly available.

Restricted Stock

From time-to-time, the Company grants shares of restricted stock to employees and non-employee directors of the Company. Employee shares vest over a three year period at a rate of one-third on the annual anniversary date of the grant, and the non-employee directors' shares vest six-months from the date of grant.

The weighted average grant date fair value of the shares granted in 2013, 2012, and 2011 was $22.5 million, $2.8 million and $1.5 million, respectively. At December 31, 2013, 2012 and 2011, the unrecognized compensation expense related to non-vested restricted stock totaled $10.0 million, $1.6 million and $2.7 million, respectively. The weighted average remaining vesting period as of December 31, 2013, 2012, and 2011 was 1.2 years.

In February 2012, the Company realized compensation expense of $2.6 million primarily from the accelerated vesting of all unvested employee restricted stock shares outstanding at the time of the change in control in the Company resulting from the Recapitalization as described in Note 2, "*Recapitalization*."

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

The following table sets forth the restricted stock transactions for the years ended December 31, 2013, 2012 and 2011:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value(1) (In thousands)
Unvested outstanding shares at December 31, 2010	885,224	$ 6.51	$ 4,886
Granted	279,907	5.23	
Vested	(209,710)	7.81	
Forfeited	(117,934)	5.26	
Unvested outstanding shares at December 31, 2011	837,487	$ 5.92	$ 7,864
Granted	312,900	8.91	
Vested	(334,838)	5.44	
Accelerated vesting(2)	(547,649)	7.43	
Forfeited			
Unvested outstanding shares at December 31, 2012	267,900	$ 8.72	$ 1,854
Granted	3,266,450	6.90	
Vested	(543,563)	6.43	
Accelerated vesting(3)	(142,610)	7.10	
Forfeited	(204,783)	6.96	
Unvested outstanding shares at December 31, 2013	2,643,394	$ 7.16	$ 10,204

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(1) The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2013, 2012, and 2011 of the underlying stock multiplied by the number of restricted shares. The total fair value of shares vested were $3.5 million, $9.2 million and $0.8 million for the years ended 2013, 2012, and 2011, respectively.

(2) Represents accelerated vesting of all unvested employee restricted stock shares outstanding at the time of the change in control in the Company resulting from the Recapitalization.

(3) Represents accelerated vesting of unvested employee restricted stock at the time of severance in conjunction with the Company's divestiture of non-core assets.

Stock Appreciation Rights

In May 2011, the Company granted 0.5 million stock appreciation rights (SARs) under the Plan at an exercise price of $5.19 per share of common stock, which was the weighted average closing price of the Company's common stock on the date of grant. Compensation expense related to the SARs is based on fair value re-measured at each reporting period and recognized over the vesting period (generally four years). As of December 31, 2011, the fair value calculation resulted in $0.8 million unrealized loss recognized as share-based compensation expense, a component of "*General and administrative*" on the consolidated statements of operations, and $0.1 million as restructuring costs on the consolidated statements of operations during the year ended December 31, 2011. The SARs expire ten years from date of grant and upon exercise. The terms of the SARs require settlement in cash, net of applicable taxes. In February 2012, the Company accelerated vesting and exercise of all unvested SARs under the Plan, due to the change in control of the Company resulting from the Recapitalization

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

described in Note 2, "*Recapitalization*." The Company settled the SARs in cash, resulting in $2.2 million of share-based compensation expense recognized for the year ended December 31, 2012. The realized compensation expense was partially offset by the reversal of $0.8 million of unrealized losses recorded at December 31, 2011.

A summary of the non-vested SARs as of December 31, 2011, and changes during the year ended December 31, 2012, is presented below:

	Number	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2011	418,333	$ 5.19
Granted		
Vested	(84,418)	5.19
Accelerated vesting[(1)]	(333,915)	5.19
Forfeited		
Non-vested at December 31, 2012		

(1) Represents accelerated vesting of all unvested employee SARs outstanding at the time of the change in control in the Company resulting from the Recapitalization.

The Company uses the Black-Scholes option pricing model to compute the fair value of the SARs. The following assumptions were used in calculating fair value:

The risk-free interest rate is based on the zero coupon United States Treasury yield for the expected life of the grant.

The dividend yield on the Company's common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.

The volatility of the Company's common stock is based on volatility of the market price of the Company's common stock over a period of time equal to the expected term and ending on the grant date.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. INCOME TAXES

Income tax benefit (provision) for the indicated periods is comprised of the following:

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Current:			
Federal	$ (1,523)	$	$ (253)
State		121	
	(1,523)	121	(253)
Deferred:			
Federal	145,098	12,265	(6,549)
State	14,141	795	
	159,239	13,060	(6,549)
Total income tax benefit (provision)	$ 157,716	$ 13,181	$ (6,802)

The actual income tax benefit (provision) differs from the expected income tax benefit (provision) as computed by applying the United States Federal corporate income tax rate of 35% for each period as follows:

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Expected tax benefit (provision)	$ 483,132	$ 23,485	$ (1,836)
State income tax expense, net of federal benefit(1)	15,904	455	(557)
Goodwill impairment	(80,106)		
Merger costs		(3,580)	
Debt related costs	(2,465)	(3,239)	
Reduction in deferred tax asset	(1,550)	(3,218)	(5,957)
Change in valuation allowance and related items	(262,847)		1,883
Other	5,648	(722)	(335)
Total income tax benefit (provision)	$ 157,716	$ 13,181	$ (6,802)

(1) Included in this amount for the year ended December 31, 2013, is approximately $4.4 million related to the goodwill impairment.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. INCOME TAXES (Continued)

The components of net deferred income tax assets and (liabilities) recognized are as follows:

	December 31, 2013	December 31, 2012
	(In thousands)	
Deferred current income tax assets:		
Unrealized hedging transactions	$ 6,028	$ 3,588
Other	551	1,719
Gross deferred current income tax assets	6,579	5,307
Valuation allowance	(2,953)	
Deferred current income tax assets	$ 3,626	$ 5,307
Deferred current income tax liabilities:		
Change in accounting method[(1)]	$ (12,100)	$
Deferred current income tax liabilities	$ (12,100)	$
Net current deferred income tax assets (liabilities)	$ (8,474)	$ 5,307
Deferred noncurrent income tax assets:		
Net operating loss carry-forwards	$ 551,567	$ 157,316
Share-based compensation expense	8,628	1,063
Asset retirement obligations	14,454	28,488
Other	9,439	2,299
Gross deferred noncurrent income tax assets	584,088	189,166
Valuation allowance	(262,179)	(2,285)
Deferred noncurrent income tax assets	$ 321,909	$ 186,881

Deferred noncurrent income tax liabilities:		
Book-tax differences in property basis	$ (286,155)	$ (339,607)
Change in accounting method[(1)]	(24,201)	
Unrealized hedging transactions	(1,326)	(2,620)
Investment in unconsolidated entities	(1,753)	(4,156)
Other		(553)
Deferred noncurrent income tax liabilities	$ (313,435)	$ (346,936)
Net noncurrent deferred income tax assets (liabilities)	$ 8,474	$ (160,055)

(1) In December 2013 the Company filed Form 3115, Application for Change in Accounting Method, related to certain property, plant and equipment expenditures and the tax impacts of the filing are reflected in the amounts above.

ASC 740, *Income Taxes* (ASC 740) prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company has no unrecognized tax benefits for the years ended December 31, 2013, 2012 or 2011.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. INCOME TAXES (Continued)

Generally, the Company's income tax years 2010 through 2013 remain open and subject to examination by Federal tax authorities or the tax authorities in Louisiana, Mississippi, North Dakota, Oklahoma, Texas, Ohio, Pennsylvania and certain other small state taxing jurisdictions where the Company has its principal operations. In certain jurisdictions the Company operates through more than one legal entity, each of which may have different open years subject to examination.

The Company recognizes interest and penalties accrued to unrecognized benefits in "*Interest expense and other, net*" in its consolidated statements of operations. For the years ended December 31, 2013, 2012 and 2011 the Company recognized no interest and penalties.

As of December 31, 2013, the Company has available, to reduce future taxable income, a United States net operating loss carryforwards (NOLs) of approximately $1.5 billion (net of excess income tax benefits not recognized of $4.2 million) before consideration of any valuation allowance which expires in the years 2020 thru 2033. A portion of these net operating loss carryforwards are subject to the ownership change limitation provisions of Section 382 of the Internal Revenue Code (IRC). The Company also has various net state NOL carryforwards of approximately $20.4 million, before consideration of any valuation allowance with varying lengths of allowable carryforward periods ranging from five to 20 years that can be used to offset future state taxable income.

The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. The Company evaluated possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies in making this assessment. A significant item of objective negative evidence considered was the cumulative book loss over the three-year period ended December 31, 2013 driven primarily by the full cost ceiling impairments in 2013 which limit the ability to consider other subjective evidence such as the Company's anticipated future growth. As a result of the Company's analysis, it was concluded that as of December 31, 2013 a valuation allowance should be established against the Company's net deferred tax asset. The Company recorded a valuation allowance as of December 31, 2013 of $265.1 million, $3.0 million of which was classified as current, an increase of $262.8 million from December 31, 2012. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized.

On September 13, 2013, the United States Treasury Department and the Internal Revenue Service issued final tangible property regulations (the tangible property regulations) under provisions that include IRC Sections 162, 167 and 263(a). The tangible property regulations apply to amounts paid to acquire, produce or improve tangible property, as well as dispositions of such property. The general effective date of the tangible property regulations are for tax years beginning on or after January 1, 2014. The Company may be required to make tax accounting method changes as of January 1, 2014; however, based on the Company's analysis to date management does not anticipate the impacts of the tangible property regulations to be material to the Company's consolidated financial position, its results of operations, or both.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. EARNINGS PER SHARE

The following represents the calculation of earnings per share:

	Years Ended December 31,		
	2013	2012	2011
	(In thousands, except per share amounts)		
Basic:			
Net income (loss) available to common stockholders	$ (1,233,407)	$ (142,330)	$ (1,403)
Weighted average basic number of common shares outstanding	379,621	156,494	26,258
Basic net income (loss) per common share	$ (3.25)	$ (0.91)	$ (0.05)
Diluted:			
Net income (loss) available to common stockholders	$ (1,233,407)	$ (142,330)	$ (1,403)
Weighted average basic number of common shares outstanding	379,621	156,494	26,258
Common stock equivalent shares representing shares issuable upon:			
Exercise of stock options	Anti-dilutive	Anti-dilutive	
Exercise of February 2012 Warrants	Anti-dilutive	Anti-dilutive	
Exercise of August 2012 Warrants	Anti-dilutive	Anti-dilutive	
Vesting of restricted shares	Anti-dilutive	Anti-dilutive	Anti-dilutive
Conversion of 2017 Notes	Anti-dilutive	Anti-dilutive	
Conversion of preferred stock	Anti-dilutive	Anti-dilutive	
Conversion of Series A Preferred Stock	Anti-dilutive		
Weighted average diluted number of common shares outstanding	379,621	156,494	26,258
Diluted net income (loss) per common share	$ (3.25)	$ (0.91)	$ (0.05)

Common stock equivalents, including stock options, restricted shares, warrants, convertible debt and convertible preferred stock, totaling 149.5 million shares were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive for the year ended December 31, 2013 due to the net loss. Common stock equivalents, including stock options, warrants, convertible debt and convertible preferred stock, totaling 215.8 million shares were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive for the year ended December 31, 2012. There were no convertible shares for the year ended December 31, 2011.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	December 31, 2013	December 31, 2012
	(In thousands)	
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	$ 129,355	$ 143,794
Joint interest accounts	170,907	113,671
Affiliated partnership	500	475
Other	11,756	4,869
	$ 312,518	$ 262,809
Prepaids and other:		
Prepaid	$ 5,636	$ 3,690
Income tax receivable	10,404	2,993
Other	58	8
	$ 16,098	6,691
Accounts payable and accrued liabilities:		
Trade payables	$ 87,661	$ 136,715
Accrued oil and natural gas capital costs	292,472	282,245
Revenues and royalties payable	124,222	91,761
Accrued interest expense	82,570	45,201
Accrued employee compensation	2,272	12,321
Accrued lease operating expenses	21,469	10,964
Drilling advances from partners	24,882	8,840
Accounts payable to affiliated partnership	679	822
Other	362	1,682
	$ 636,589	$ 590,551

15. SUBSEQUENT EVENT

The Company has entered into a purchase and sale agreement to divest non-core assets in East Texas for $450 million. The transaction is expected to close in the second quarter of 2014, subject to customary closing conditions and price adjustments, with an effective date of April 1, 2014. Upon the closing of the sale of the non-core assets in East Texas, we expect the borrowing base under the Company's Senior Credit Agreement will be reduced by $100 million.

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SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

The reserves estimates shown herein for the years ended December 31, 2013 and 2012 have been independently evaluated by Netherland, Sewell, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland, Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserves report incorporated herein are Mr. J. Carter Henson, Jr. and Mr. Mike K. Norton. Mr. Henson has been practicing consulting petroleum engineering at Netherland, Sewell since 1989. Mr. Henson is a Licensed Professional Engineer in the State of Texas (No. 73964) and has over 30 years of practical experience in petroleum engineering, with over 24 years' experience in the estimation and evaluation of reserves. He graduated from Rice University in 1981 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Norton has been practicing consulting petroleum geology at Netherland, Sewell since 1989. Mr. Norton is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441) and has over 30 years of practical experience in petroleum geosciences, with over 24 years' experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. Our estimated proved reserves for the year ended December 31, 2011 were prepared by Forrest A. Garb & Associates, an independent oil and natural gas reservoir engineering consulting firm.

Our board of directors has established an independent reserves committee composed of four outside directors, all of whom have experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Vice President of Corporate Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to our board of directors as to whether to accept the report prepared by our independent consulting petroleum engineers. In 2013, Ms. Tina Obut, our Vice President of Corporate Reserves was the technical person primarily responsible for overseeing the preparation of the annual reserve report by Netherland, Sewell.

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She graduated from Marietta College with a Bachelor of Science degree in Petroleum Engineering, received a Master of Science degree in Petroleum and Natural Gas Engineering from Penn State University and a Master of Business Administration degree from the University of Houston.

The reserves information in this Annual Report on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent the Company acquires additional properties containing proved reserves or conduct successful exploration and development activities or both, the Company's proved reserves will decline as reserves are produced.

The following table illustrates the Company's estimated net proved reserves, including changes, and proved developed reserves for the periods indicated. The oil and natural gas liquids prices as of December 31, 2013 and 2012 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate spot price which equates to $96.94 per barrel and $94.71 per barrel, respectively. The oil and natural gas liquids prices as of December 31, 2011 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate posted price which equates to $96.19 per barrel. The oil and natural gas liquids prices were adjusted by lease or field for quality, transportation fees, and regional price differentials. The natural gas prices as of December 31, 2013, 2012 and 2011 are based on the respective 12-month unweighted average of the first of the month prices of the Henry Hub spot price which equates to $3.670 per MMBtu, $2.757 per MMBtu and $4.12 per MMBtu, respectively. All prices are adjusted by

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lease or field for energy content, transportation fees, and regional price differentials. All prices are held constant in accordance with SEC guidelines. All proved reserves are located in the United States.

	Proved Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
Proved reserves, December 31, 2010	13,086	53,608	2,375	24,395
Extensions and discoveries	339	20	1	343
Purchase of minerals in place	5			5
Production	(884)	(2,662)	(176)	(1,504)
Sale of minerals in place				
Revision of previous estimates	(175)	(10,912)	(190)	(2,182)
Proved reserves, December 31, 2011	12,371	40,054	2,010	21,057
Extensions and discoveries	11,691	6,742	352	13,167
Purchase of minerals in place	66,240	71,560	3,433	81,600
Production	(2,415)	(4,554)	(268)	(3,442)
Sale of minerals in place	(1,789)	(2,025)		(2,127)
Revision of previous estimates	1,280	(15,632)	(144)	(1,470)
Proved reserves, December 31, 2012	87,378	96,145	5,383	108,785
Extensions and discoveries	61,160	25,364	4,344	69,731
Purchase of minerals in place	2,770	1,791	162	3,231
Production	(10,148)	(8,003)	(683)	(12,165)
Sale of minerals in place	(17,417)	(25,717)	(1,611)	(23,314)
Revision of previous estimates	(9,233)	(19,832)	2,237	(10,301)
Proved reserves, December 31, 2013	114,510	69,748	9,832	135,967

	Proved Developed Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2013	44,113	37,714	4,206	54,605
December 31, 2012	38,429	58,785	3,172	51,399
December 31, 2011	8,643	20,997	1,237	13,381

	Proved Undeveloped Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2013	70,397	32,034	5,626	81,362

December 31, 2012	48,949	37,360	2,211	57,386
December 31, 2011	3,728	19,057	773	7,676

The Company's reserves have been estimated using deterministic methods. The total proved reserve increase of 27,182 MBoe during 2013 is comprised of 3.2 MMBoe in proved developed and 24.0 MMBoe in proved undeveloped reserves.

During 2013, the Company divested 23.3 million Boe of non-core assets. As a result of the Company's development program, 69.7 million Boe of proved reserves were added, primarily in the Bakken / Three Forks and El Halcón areas. The negative revision of 10.3 million Boe is largely due to Woodbine drilling results leading to a general reduction in EUR.

During 2012, through several transactions, the Company acquired 81.6 million Boe in proved reserves primarily in the Bakken / Three Forks area and Woodbine / Eagle Ford area. As a result of

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the Company's active development programs in these areas, the Company added 13.2 million Boe. In 2012, the Company had one divestiture of 2.1 million Boe in its non-core area. The small negative revision of 1.5 million Boe comes mostly from the Company's non-core areas and is due to lower gas prices, well performance changes and expiring proved undeveloped locations.

The Company added 0.3 million Boe in proved reserve extensions and discoveries in 2011 primarily as a result of its development drilling in its Electra/Burkburnett Field in North Texas and in its La Copita Field in South Texas. A significant portion of these reserves is a result of drilling locations in Electra/Burkburnett, Northeast Fitts and Allen Fields that were not booked as proved locations as of December 31, 2010. The revisions of previous reserve estimates in 2011 decreased proved reserves by 2.2 million Boe or approximately 9% of proved reserves at the beginning of the year. The revisions include a positive increase of 0.9 million Boe or 4% of the beginning of the year proved reserves caused by higher crude oil and natural gas prices. This positive revision was offset by the downward revision of 1.4 million Boe caused by the transfer of proved reserves to unproved categories as a result of updated geological and engineering evaluations and changes to the Company development plans during 2011, and 1.7 million Boe of downward revisions were mostly due to changes in well performance.

At December 31, 2013, our estimated proved undeveloped (PUD) reserves were approximately 81.4 MMBoe, a 24.0 MMBoe net increase over the previous year's estimate of 57.4 MMBoe. The following details the changes in PUD reserves for 2013 (MBoe):

Beginning proved undeveloped reserves at December 31, 2012	57,386
Undeveloped reserves transferred to developed	(12,901)
Revisions	(8,532)
Purchases	743
Divestitures	(8,451)
Extension and discoveries	53,117
Ending proved undeveloped reserves at December 31, 2013	81,362

The increase in proved undeveloped reserves was primarily attributable to extensions of approximately 53 MMBoe, which were largely in the Bakken / Three Forks and El Halcón areas, where active drilling resulted in the expansion of proven areas. Approximately 19% of the proved undeveloped reserve extensions are associated with well locations that are more than one offset away from existing producing wells. A minor portion of the increase in proved undeveloped reserves of approximately 1 MMBoe was associated with several minor property acquisitions in the Bakken / Three Forks and El Halcón areas.

Partially offsetting the increase in proved undeveloped reserves were decreases due to transfers, divestitures, and technical revisions. Reserve transfers of approximately 13 MMBoe were associated with drilling of PUD locations in the Bakken / Three Forks, Woodbine and El Halcón areas. Divestitures of undeveloped reserves of approximately 8 MMBoe relate to several non-core property sales completed during the second half of 2013. Downward revisions of approximately 9 MMBoe were largely in the Halliday field of the Woodbine area, where 2013 development drilling results led to the removal of PUD locations in the lower quality perimeter of the field and a reduction in EUR for the remaining PUD locations.

As of December 31, 2013, all of the Company's proved undeveloped reserves are planned to be developed within five years from the date they were initially recorded. During 2013, approximately $749.0 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

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For wells classified as proved developed producing where sufficient production history existed, reserves were based on individual well performance evaluation and production decline curve extrapolation techniques. For undeveloped locations and wells that lacked sufficient production history, reserves were based on analogy to producing wells within the same area exhibiting similar geologic and reservoir characteristics, combined with volumetric methods. The volumetric estimates were based on geologic maps and rock and fluid properties derived from well logs, core data, pressure measurements, and fluid samples. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and volumetric estimates for each area or field. PUD locations were limited to areas of uniformly high quality reservoir properties, between existing commercial producers.

Reliable technologies were used to determine areas where PUD locations are more than one offset away from a producing well. These technologies include seismic data, wire line open hole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic estimated ultimate recoveries from individual producing wells. The Company's management team has been a leader in data gathering and evaluation in these areas and was instrumental in developing consortiums that allow various operators to exchange data. The Company relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves.

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depletion, depreciation and accretion.

	December 31,		
	2013	2012	2011
	(In thousands)		
Evaluated oil and natural gas properties[(1)]	$ 4,960,467	$ 2,669,245	$ 715,666
Unevaluated oil and natural gas properties	2,028,044	2,326,598	
	6,988,511	4,995,843	715,666
Accumulated depletion[(1)]	(2,189,515)	(588,207)	(501,993)
	$ 4,798,996	$ 4,407,636	$ 213,673

(1) Amounts do not include costs for the Company's gas gathering systems and related support equipment.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Years Ended December 31,		
	2013	2012[(1)]	2011
	(In thousands)		
Property acquisition costs, proved	$ 71,443	$ 1,495,372	$ 724
Property acquisition costs, unproved	436,438	2,324,439	
Exploration and extension well costs	1,182,110	232,685	7,135
Development costs	748,962	254,499	17,355

Total costs	$	2,438,953	$	4,306,995	$	25,214

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(1)
Property acquisition costs include preferred stock issued for Williston Basin Assets of $695.2 million, common stock issued for GeoResources, Inc. of $321.4 million, and common stock issued for East Texas Assets of $130.6 million for the year ended December 31, 2012.

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following Standardized Measure of Discounted Future Net Cash Flows has been developed utilizing ASC 932, *Extractive Activities Oil and Gas* (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure) be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- future costs and selling prices will probably differ from those required to be used in these calculations;
- due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- future net revenues may be subject to different rates of income taxation.

At December 31, 2013, 2012 and 2011, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor.

The Standardized Measure is as follows:

	Years Ended December 31,		
	2013	**2012**	**2011**
		(In thousands)	
Future cash inflows	$ 11,351,887	$ 8,714,938	$ 1,440,088
Future production costs	(3,680,190)	(2,726,382)	(582,662)
Future development costs	(2,182,509)	(1,416,967)	(102,231)
Future income tax expense	(108,871)	(651,070)	(205,457)
Future net cash flows before 10% discount	5,380,317	3,920,519	549,738
10% annual discount for estimated timing of cash flows	(2,634,322)	(1,966,467)	(262,849)
Standardized measure of discounted future net cash flows	$ 2,745,995	$ 1,954,052	$ 286,889

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Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2013:

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Beginning of year	$ 1,954,052	$ 286,889	$ 278,047
Sale of oil and natural gas produced, net of production costs	(761,716)	(172,971)	(64,451)
Purchase of minerals in place	94,844	1,898,345	104
Sales of minerals in place	(434,421)	(53,452)	
Extensions and discoveries	1,125,162	290,668	24,659
Changes in income taxes, net	344,165	(195,007)	(18,691)
Changes in prices and costs	(107,780)	(2,985)	93,411
Previously estimated development costs incurred	340,577	36,142	11,209
Net changes in future development costs	211,350	(124,483)	1,940
Revisions of previous quantities	(219,424)	(32,681)	(49,782)
Accretion of discount	231,707	87,075	36,425
Changes in production rates and other	(32,521)	(63,488)	(25,982)
End of year	$ 2,745,995	$ 1,954,052	$ 286,889

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SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table presents selected quarterly financial data derived from the Company's unaudited consolidated interim financial statements. The following data is only a summary and should be read with the Company's historical consolidated financial statements and related notes contained in this document.

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
2013				
Total operating revenues	$ 190,854	$ 214,343	$ 305,007	$ 289,302
Income (loss) from operations	32,031	31,841	(1,147,020)	(207,799)
Net income (loss)	5,465	37,088	(854,827)	(410,388)
Net income (loss) available to common stockholders(1)	5,465	36,372	(859,897)	(415,347)
Net income (loss) per share of common stock:				
Basic	$ 0.02	$ 0.10	$ (2.19)	$ (1.01)
Diluted	$ 0.01	$ 0.08	$ (2.19)	$ (1.01)

	Quarters Ended			
	March 31	June 30	September 30	December 31
2012				
Total operating revenues	$ 26,917	$ 23,341	$ 73,307	$ 124,757
Income (loss) from operations	(9,785)	(7,220)	(4,569)	(8,143)
Net income (loss)	(33,322)	7,659	(20,181)	(8,041)
Net income (loss) available to common stockholders	(34,424)	(79,684)	(20,181)	(8,041)
Net income (loss) per share of common stock:				
Basic	$ (0.50)	$ (0.59)	$ (0.11)	$ (0.04)
Diluted	$ (0.50)	$ (0.59)	$ (0.11)	$ (0.04)

(1)

The volatility in *"Net income (loss) available to common stockholders"* is substantially due to the Company's full cost ceiling impairments recorded during the third and fourth quarters of 2013, the Company's other operating property equipment impairment in the third quarter of 2013 and the Company's goodwill impairment in the third quarter of 2013. See Note 1, "*Summary of Significant Events and Accounting Policies*" and Note 5, "*Oil and Natural Gas Properties*" for additional information.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

As previously reported on Form 8-K filed with the SEC on April 4, 2012 (the "prior 8-K"), on April 3, 2012, we dismissed our prior independent registered public accounting firm and appointed Deloitte & Touche LLP as our independent registered public accounting firm for the 2012 fiscal year. For more information, please refer to the prior 8-K.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(f) and 15d-15(f), of the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992 as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2013 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Management has assessed, and our independent registered public accounting firm, Deloitte & Touche LLP, has audited, our internal control over financial reporting as of December 31, 2013. The unqualified reports of management and Deloitte & Touche LLP thereon are included in Item 8. *Consolidated Financial Statements and Supplementary Data* of this Annual Report on Form 10-K and are incorporated by reference herein.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act, during the three months ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

The Company's Code of Conduct and Code of Ethics for the Chief Executive Officer and Senior Financial Officers can be found on the Company's internet website located at *www.halconresources.com*. Any stockholder may request a printed copy of such materials by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its internet website. The waiver information will remain on the website for at least twelve months after the initial disclosure of such waiver.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2013 with respect to compensation plans (including individual compensation arrangements) under which our equity securities are authorized for issuance.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options and Rights(a)	Weighted-Average Exercise Price of Outstanding Options and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by security holders[1]	13,059,639[2]	$ 7.15	25,733,972
Equity compensation plans not approved by security holders			
	13,059,639[2]	$ 7.15	25,733,972

(1) Represents information for the 2012 Long-Term Incentive Plan.

(2) Includes 2,643,394 shares of restricted stock not yet vested.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements:

The consolidated financial statements of the Company and its subsidiaries and reports of independent registered public accounting firms listed in Section 8 of this Annual Report on Form 10-K are filed as a part of this Annual Report on Form 10-K.

(2) Consolidated Financial Statements Schedules:

All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:

2.1	Securities Purchase Agreement dated December 21, 2011 by and between RAM Energy Resources, Inc. and Halcón Resources LLC (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed December 22, 2011).
2.1.1	First Amendment to Securities Purchase Agreement dated January 4, 2012 by and between RAM Energy Resources, Inc. and Halcón Resources LLC (Incorporated by reference to Exhibit 2.1.1 of our Current Report on Form 8-K filed January 5, 2012).
2.2	Agreement and Plan of Merger, dated as of April 24, 2012 by and among Halcón Resources Corporation, Leopard Sub I, Inc., Leopard Sub II, LLC and GeoResources, Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed April 25, 2012).
2.3	Agreement of Sale and Purchase dated May 8, 2012 between NCL Appalachian Partners, L.P., as Seller, and Halcón Energy Properties, Inc., as Buyer (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed July 2, 2012).
2.4	Purchase and Sale Agreement dated as of the 5th day of June, 2012, among CH4 Energy II, LLC, PetroMax Leon, LLC and Petro Texas LLC and Halcón Energy Properties, Inc., and joined by PetroMax Operating Co., Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed August 7, 2012).
2.5	Reorganization and Interest Purchase Agreement dated October 19, 2012 by and among Halcón Energy Properties, Inc., Petro-Hunt, L.L.C. and Pillar Energy, LLC (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed October 22, 2012).
3.1	Amended and Restated Certificate of Incorporation of RAM Energy Resources, Inc. dated February 8, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed February 9, 2012).
3.1.1	Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Halcón Resources Corporation, effective as of February 10, 2012 (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed February 9, 2012).
3.1.2	Certificate of Designation, Preferences, Rights and Limitations of 8% Automatically Convertible Preferred Stock of Halcón Resources Corporation dated March 2, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed March 5, 2012).

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3.1.3 Certificate of Elimination of 8% Automatically Convertible Preferred Stock dated November 30, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed December 4, 2012).

3.1.4 Certificate of Designation, Preferences, Rights and Limitations of 8% Automatically Convertible Preferred Stock of Halcón Resources Corporation dated December 5, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed December 11, 2012).

3.1.5 Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Halcón Resources Corporation dated January 17, 2013 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed January 23, 2013).

3.1.6 Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Halcón Resources Corporation, effective as of May 23, 2013 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed May 29, 2013).

3.1.7 Certificate of Designations, Preferences, Rights and Limitations of 5.75% Series A Convertible Perpetual Preferred Stock of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed June 18, 2013).

3.1.8 Certificate of Elimination of 8% Automatically Convertible Preferred Stock of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed June 18, 2013).

3.2 Fourth Amended and Restated Bylaws of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed November 6, 2012).

4.1 Convertible Promissory Note dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed February 9, 2012).

4.2 Warrant Certificate dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed February 9, 2012).

4.3 Registration Rights Agreement dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K filed February 9, 2012).

4.4 Indenture dated as of July 16, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as Trustee, relating to Halcón Resources Corporation's 9.75% Senior Notes due 2020 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed July 17, 2012).

4.5 Registration Rights Agreement dated July 16, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein, and the initial purchaser named therein (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed July 17, 2012).

4.6 First Supplemental Indenture dated as of August 1, 2012, by and among Halcón Resources Corporation, the parties named therein as subsidiary guarantors, and U.S. Bank National Association, as Trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed August 2, 2012).

4.7 Second Supplemental Indenture dated as of August 1, 2012, by and among Halcón Resources Corporation, the parties named therein as subsidiary guarantors, and U.S. Bank National Association, as Trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed August 2, 2012).

4.8 Registration Rights Agreement dated as of August 1, 2012, among CH4 Energy II, LLC, PetroMax Leon, LLC and Petro Texas LLC and Halcón Resources Corporation (subsequently joined by U.S. King King LLC) (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed August 7, 2012).

4.9 Registration Rights Agreement dated March 5, 2012, between Halcón Resources Corporation and Barclays Capital, Inc. as lead placement agent for the benefit of the initial holders named therein (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed March 5, 2012).

4.10 Registration Rights Agreement dated as of November 6, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein, and the initial purchaser named therein (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed November 7, 2012).

4.11 Indenture dated as of November 6, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as Trustee, relating to Halcón Resources Corporation's 8.875% Senior Notes due 2021 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed November 7, 2012).

4.12 First Supplemental Indenture dated December 6, 2012, among Halcón Williston I, LLC and Halcón Williston II, LLC, the existing guarantors, Halcón Resources Corporation, the parties named therein as subsidiary guarantors and U.S. Bank National Association, as trustee, relating to the 8.875% senior notes due 2021 (Incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K filed December 11, 2012).

4.13 Third Supplemental Indenture dated December 6, 2012, among Halcón Resources Corporation and U.S. Bank National Association, as Trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.4 of our Current Report on Form 8-K filed December 11, 2012).

4.14 Registration Rights Agreement dated December 6, 2012, between Halcón Resources Corporation and Petro-Hunt Holdings LLC and Pillar Holdings LLC (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed December 11, 2012).