Ryerson Holding Corp
Form S-1/A
December 04, 2013
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As filed with the Securities and Exchange Commission on December 4, 2013.

Registration No 333-164484

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

AMENDMENT NO. 17

TO

FORM S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

RYERSON HOLDING CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	5051	26-1251524
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

227 W. Monroe, 27th Floor

Chicago, Illinois 60606

(312) 292-5000

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Mark S. Silver

Vice President and Managing Counsel

Ryerson Holding Corporation

227 W. Monroe, 27th Floor

Chicago, Illinois 60606

(312) 292-5000

(Name, address, including zip code, and telephone number, including area code, of agent for service)

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Approximate date of commencement of proposed sale to the public:

As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act, check the following box. ¨

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b2 of the Exchange Act.

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

Title of Each Class of Securities To Be Registered	Proposed Maximum Aggregate Offering Price(1)(2)	Amount of Registration Fee(3)
Common Stock, par value $0.01 per share	$300,000,000	$34,380

(1) Estimated solely for purposes of determining the registration fee in accordance with Rule 457(o) under the Securities Act of 1933, as amended.
(2) Includes shares of common stock that may be purchased by the underwriters to cover over-allotments, if any. See Underwriting.
(3) Previously paid.

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until this Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. Neither we nor the selling stockholders may sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and is not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to Completion

Preliminary Prospectus dated , 2013

PROSPECTUS

Shares

Ryerson Holding Corporation

Common Stock

We are selling shares of our common stock. The selling stockholders identified in this prospectus have granted the underwriters an option to purchase up to additional shares of common stock to cover over-allotments. We will not receive any proceeds from the sale of shares by the selling stockholders.

This is the initial public offering of our common stock. We currently expect the initial public offering price to be between $ and $ per share. We have applied to have our common stock listed on the New York Stock Exchange under the symbol RYI.

Investing in our common stock involves a high degree of risk. See Risk Factors beginning on page 18.

	Per Share	Total
Public Offering Price	$	$
Underwriting Discount(1)	$	$
Proceeds, before expenses, to us	$	$

(1) See Underwriting for a description of the compensation payable to the underwriters.

The underwriters may also purchase up to an additional shares from the selling stockholders, at the public offering price, less the underwriting discount, within 30 days of the date of this prospectus.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares to purchasers on or about , 2014.

BofA Merrill Lynch **Deutsche Bank Securities** **BMO Capital Markets**

J.P. Morgan **Jefferies**

Wells Fargo Securities **KeyBanc Capital Markets** **Citigroup**

Macquarie Capital

The date of this prospectus is , 2013

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You should rely only on the information contained in this prospectus and any free writing prospectus we may specifically authorize to be delivered or made available to you. We have not, and the selling stockholders and the underwriters have not, authorized anyone to provide you with different information. We are not, and the selling stockholders and the underwriters are not, making an offer of these securities in any jurisdiction where the offer is not permitted. You should not assume that the information contained in this prospectus and any free writing prospectus we may specifically authorize to be delivered or made available to you is accurate as of any date other than the date on the front of this prospectus, regardless of its time of delivery or of any sale of shares of our common stock. Our business, financial condition, results of operations and prospects may have changed since that date.

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INDUSTRY AND MARKET DATA

In this prospectus, we rely on and refer to information and statistics regarding the steel processing industry and our market share in the sectors in which we compete. We obtained this information and these statistics from sources other than us, which we have supplemented where necessary with information from publicly available sources, discussions with our customers and our own internal estimates. References in this prospectus to:

- American Iron and Steel Institute (AISI) refer to its SteelWorks website from March 2013, or its Steel Production Capacity Utilization index from November 2013;
- The Institute for Supply Management refer to its October 2013 Manufacturing ISM Report on Business®;
- United States Federal Reserve refer to its September 2013 Summary of Economic Projections ;
- The Metals Service Center Institute (MSCI) refer to its October 2013 edition of MSCI Metal Activity Report ;
- The Federal Reserve Bank of Philadelphia refer to its June 2013 issue of The Livingston Survey ;
- Euromonitor refer to its February 2013 Consumer Appliances in the U.S. report;
- IBIS Worldwide refer to its January 2013 Heating & Air Conditioning in the U.S. report;
- LMC Automotive refer to its Q3 2013 data;
- MarketLine refer to its May 2013 Machinery in the United States report;
- Wood Mackenzie refer to its October 2013 Metals Market Service Monthly Update reports;
- Bureau of Economic Analysis refer to its November 2013 Auto and Truck Seasonal Adjustment data; and
- Metal Center News refer to its September 2013 Service Center Top 50 report.

We use these sources and estimates and believe them to be reliable, but we cannot give you any assurance that any of the projected results will be achieved.

PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. This summary does not contain all of the information that you should consider before investing in our common stock. You should read the entire prospectus carefully together with our consolidated financial statements and the related notes appearing elsewhere in this prospectus before making an investment decision. This prospectus contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in such forward-looking statements as a result of certain factors, including those discussed in the Risk Factors and other sections of this prospectus.

Except as otherwise indicated herein or as the context otherwise requires, references in this prospectus to Ryerson Holding, the Company, we, our, and us refer to Ryerson Holding Corporation and its direct and indirect subsidiaries (including Ryerson Inc.). The term Ryerson refers to Ryerson Inc., a direct wholly owned subsidiary of Ryerson Holding, together with its subsidiaries on a consolidated basis. Platinum refers to Platinum Equity, LLC and its affiliated investment funds, certain of which are our principal stockholders, and Platinum Advisors refers to Platinum Equity Advisors, LLC. We refer to the issuance of our common stock being offered hereby as the offering.

Our Company

We believe we are one of the largest processors and distributors of metals in North America measured in terms of sales, with global operations in North America, China and a recently established presence in Brazil. Our industry is highly fragmented with the largest companies accounting for only a small percentage of total market share. Our customer base ranges from local, independently owned fabricators and machine shops to large, international original equipment manufacturers. We process and distribute a full line of over 75,000 products in stainless steel, aluminum, carbon steel and alloy steels and a limited line of nickel and red metals in various shapes and forms. More than one-half of the products we sell are processed to meet customer requirements. We use various processing and fabricating techniques to process materials to a specified thickness, length, width, shape and surface quality pursuant to customer orders. For the year ended December 31, 2012, we purchased 2.1 million tons of materials from suppliers throughout the world. For the nine months ended September 30, 2013, our Adjusted EBITDA, excluding LIFO expense was $128.1 million, revenue was $2,657.8 million and net income was $8.2 million. See note 4 in Summary Historical Consolidated Financial and Other Data for a reconciliation of Adjusted EBITDA to net income.

We operate over 90 facilities across North America, six facilities in China and one in Brazil. Our service centers are strategically located in close proximity to our customers, which allows us to quickly process and deliver our products and services, often within the next day of receiving an order. We own, lease or contract a fleet of tractors and trailers, allowing us to efficiently meet our customers delivery demands. In addition, our scale enables us to maintain low operating costs. Our operating expenses as a percentage of sales for the years ended December 31, 2011 and 2012 were 11.8% and 12.6%, respectively.

We serve more than 40,000 customers across a wide range of manufacturing end markets. We believe the diverse end markets we serve reduce the volatility of our business in the aggregate. Our geographic network and broad range of products and services allow us to serve large, international manufacturing companies across multiple locations.

Following this offering, because Platinum will control more than 50% of the voting power of our common stock, we will be considered a controlled company under the New York Stock Exchange rules. As such, we are permitted, and have elected, to opt out of compliance with certain NYSE corporate governance requirements. Accordingly, stockholders will not have the same protections afforded to stockholders of companies that are

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subject to all of the NYSE corporate governance requirements. See Risk Factors We are exempt from certain corporate governance requirements because we are a controlled company within the meaning of the NYSE rules for a summary of the effects of a controlled company on investors.

We are broadly diversified in our end markets and product lines in North America, as detailed below.

2012 Sales by End Market

2012 Sales by Product

(1) Other includes copper, brass, nickel, pipe, valves and fittings.

Industry and End Market Outlook

Ryerson participates in the metals service center industry providing steel, aluminum and other metals products across a wide range of industrial manufacturing end markets. Our business performance is therefore impacted by a number of factors tied to industrial activity, including economic growth, end market demand and metals pricing. With steel products accounting for 76% of our 2012 sales, it is the largest driver of our business. Aluminum products account for 21% of our business, with other metals accounting for the remainder.

Macroeconomic Outlook. Steel is utilized in a diverse range of manufacturing and fabrication applications with a variety of end market demand drivers. The primary drivers of demand for the steel industry are the construction, automotive, machinery and equipment, and energy end markets, which, according to the American Iron and Steel Institute, account for approximately 85% of shipments collectively. As evidenced by our end market sales segmentation, we are not reliant on a single specific sector, but rather broader diversified industrial activity. Our primary end markets include industrial equipment and fabrication, transportation equipment, heavy equipment, electrical machinery and oil and gas. We believe that we are well positioned in these markets and that they are poised for growth as the broader industrial sectors continue to grow. The charts below, which reflect the most recently available data from AISI, show our end market exposure as well as the broader steel market.

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2012 Steel Shipments by Market Classification (AISI)

Source: American Iron and Steel Institute

2012 Ryerson Sales by End Market

Source: Company estimates

While some of the key end market drivers of steel industry demand do not directly overlap with our end markets, they do impact broader steel demand and pricing, which can impact our business. Recently, leading indicators in the key steel industry end markets referenced above have begun to show sustained growth and continue to build positive momentum. For example, housing starts have shown stable growth over the last 24 months, while non-residential construction, which typically lags housing, is starting to show signs of sustained improvement as well. Additionally, U.S. automotive sales continue to rise according to the Bureau of Economic Analysis, reaching 15.2 million vehicles on a seasonally adjusted annualized rate basis in October 2013 versus 14.3 million for October of 2012. Machinery and equipment, a key end market for us, includes a variety of industrial manufacturing end markets, many of which are showing signs of significant growth. This is evidenced by the Institute for Supply Management s (ISM) Purchasing Managers Index (PMI), which reached 56.4 in October 2013. The United States Federal Reserve midpoint GDP growth estimates of 3.0% and 3.25% for 2014 and 2015, respectively. Finally, the oil and gas end market continues to be a long-term growth market in steel. Much of this growth is attributable to growth in North American drilling and refining, substantially impacted by activity in United States shale oil and gas and the Canadian oil sands. Additionally, investment in new petrochemical production capacity in the United States as a result of relatively low domestic natural gas prices may further bolster steel demand. The following chart shows the historical movements of the Purchasing Managers Index.

ISM Purchasing Managers Index

According to MSCI, total inventory levels of carbon steel, stainless steel and aluminum at U.S. service centers reached a trough in August 2009 and bottomed at the lowest levels since the data series began in 1977. Although industry demand recovered in 2010, 2011 and 2012, shipments and inventory are still well below pre-downturn averages, which we believe suggests long-term growth potential that may be realized if these metrics return to, or exceed, their historical averages.

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North American Monthly Service Center Shipments **North American Monthly Service Center Inventory**

Ryerson End Market Outlook. Although our revenue for the nine months ended September 30, 2013 decreased 16.3% compared to the nine months ended September 30, 2012 due to weaker economic conditions in the metals market, according to the latest Livingston Survey, published by the Federal Reserve Bank of Philadelphia, U.S. industrial production is expected to grow by 2.8% and 3.1% in 2013 and 2014, respectively. Two of our largest end markets, industrial equipment and fabrication, include numerous diversified industrial manufacturing markets which, along with the broader economy, are showing signs of sustained growth. For example, in the U.S. major appliances and Heating Ventilation and Air Conditioning (HVAC) equipment, both markets we serve, are projected to grow at even higher rates. Specifically, major appliances are expected to grow 6.5% and 6.1% in 2014 and 2015, respectively, according to Euromonitor. According to IBIS Worldwide, HVAC is expected to grow 2.2% and 3.7% over the same periods.

In addition, we also serve the transportation equipment, heavy equipment and electrical equipment markets which are expected to show significant growth in the coming years. Transportation equipment, including commercial vehicle production, represents 17% of our sales and is expected to grow 2.8% per year in the U.S. between 2013 and 2015 according to LMC Automotive. Machinery and heavy equipment, including construction and agricultural equipment, represents 9% of our end-market sales and is projected to grow 7.1% per year in the U.S. between 2012 and 2016 according to MarketLine.

Metals Pricing. Along with improvements in volume, as indicated by demand trends in the end markets, movements in the price of steel will also impact our business. Steel prices are driven by a number of factors, including input prices, capacity utilization and foreign imports. Currently, input costs are providing support for steel pricing, as they flow directly through the pricing of the mills steel output. Additionally, we believe that recent closings of mills, including the Sparrows Point steel mill, among others, that have been dismantled, combined with continued growth in the global economy and end market demand, should begin to absorb global capacity, resulting in increased utilization. The U.S. steel industry production capacity utilization rate increased to 77.5% by the end of November 2013 from a low of 34% in December 2008, according to AISI. North American production capacity utilization levels remain below the 85% average utilization level observed in the post-consolidation restructured steel industry from 2002 to 2008. Although our average selling price decreased 10.3% in the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 due to decreases in metals prices across all of our products, with some of the largest decreases in our carbon plate, stainless steel plate and stainless steel long product lines, we believe that the combination of higher input prices, increased global demand and increased capacity utilization will support steel price increases in the near future, positively impacting our business.

Aluminum pricing also remains well below pre-downturn levels but has stabilized recently. Global output of aluminum is projected to increase 6.6% in 2014 according to Wood Mackenzie, fueled by factors including the rebound in U.S. construction and increased demand from the transportation and infrastructure markets in China.

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Industry Consolidation. The United States service center industry is a highly fragmented market with the top 50 service centers controlling approximately 25% of industry sales, according to Metal Center News, only 12 of which have sales over $1 billion. Such fragmentation has historically resulted in the smaller service centers having less negotiating leverage with both the larger consolidated steel mills, as well as larger customers. In recent years, however, there has been increased consolidation among larger players resulting in fewer customers of size for the mills and greater purchasing power for service centers. A recent example is the acquisition of Metals USA Holding Corp. by Reliance Steel & Aluminum Co. We believe that there is significant opportunity for consolidation and we expect the trend will continue.

Our Competitive Strengths

Leading Market Position in North America.

We believe we are one of the largest service center companies for carbon and stainless steel as well as aluminum based on sales in the North American market where we have a broad geographic presence with over 90 locations.

Our service centers are located near our customer locations, enabling us to provide timely delivery to customers across numerous geographic markets. Additionally, our widespread network of locations in the United States, Canada and Mexico helps us to utilize our expertise to more efficiently serve customers with complex supply chain requirements across multiple manufacturing locations. We believe this is a key differentiator among customers who need a supplier that can reliably and consistently support them. Our ability to transfer inventory among our facilities better enables us to more timely and profitably source and process specialized items at regional locations throughout our network than if we were required to maintain inventory of all products and specialized equipment at each location.

We believe with our significant footprint in the North American market, combined with our significant scale and operating leverage, a cyclical recovery of the service center industry supported by long-term growth trends in Ryerson s end-markets should allow us to experience higher growth rates relative to North American economic improvement, but there can be no guarantee that we will experience such higher growth rates.

Broad Geographic Reach across Attractive End Markets.

Our operations cover a diverse range of industries, including industrial equipment, industrial fabrication, electrical machinery, transportation equipment, heavy equipment and oil and gas. Manufacturing growth has accelerated since November 2012 as shown by the ISM index (as described in the Industry and End Market Outlook), and we believe industries we serve will provide strong demand for our products and services as the North American manufacturing economy continues to recover. We also believe that the continued trend of moving manufacturing to the United States from overseas should benefit us with our broad North American platform. In addition, we expect to benefit from continued growth in international markets that will help spur demand at domestic manufacturing facilities that sell into the global market. We believe that our ability to quickly adjust our offering based on regional and industry specific trends creates stability while also providing the opportunity to access specific growth markets.

Established Platform for Organic and Acquisition Growth.

Since 2011, we have opened seven new service centers in previously underserved North American regions. We have acquired another ten facilities to complement our existing locations and expanded the product offering in many locations based on customer demand. Over the last two years, a significant portion of our capital expenditures have been made to expand our long and plate processing capabilities at 15 existing locations. We believe that our expanded presence in select regions and products positions us well to capture further growth in these regions and products.

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Although there can be no guarantee of growth, we believe a number of our other strategies, such as improving our product mix, pricing our products and services based on the value we provide our customers, growing our large national network, and expanding our diverse operating capabilities, will provide us with growth opportunities.

In addition, we have utilized our leadership and experience in the North American markets to establish operations in China, the largest and one of the highest growth metals markets in the world, as well as in Brazil.

Given the highly fragmented nature of the service center industry, we believe there are numerous additional opportunities to acquire businesses and incorporate them into our existing infrastructure. Given our large scale and geographic reach, we believe we can add value to these businesses in a number of ways, including providing greater purchasing power, access to additional end markets and broadening product mix. Although the Company does not have any current plans to engage in any specific acquisitions, from time to time and in the ordinary course of business, the Company regularly evaluates potential acquisition opportunities.

Lean Operating Structure Providing Operating Leverage.

Since the acquisition by Platinum, we have transformed our operating model by decentralizing our operations and reducing our cost base. Decentralization has improved our customer service by moving key functions such as procurement, credit and operations support to our regional offices. From 2007 through the end of 2009, we engaged in a number of cost reduction initiatives that included a headcount reduction of approximately 1,700, representing 33% of our workforce, and the closure of 14 redundant or underperforming facilities in North America. Furthermore, in 2011, we also completed the decentralization of credit, operations, and procurement and reduced field staffing levels. In that overall period, we believe that we have generated annual fixed cost savings of approximately $200 million since 2007. We believe this reduction has improved our operating efficiency while also providing the flexibility for further growth in our targeted markets.

We have also focused on process improvements in inventory management. Despite an increase in average inventory days from 74 days in 2011 to 86 days in 2013, our average inventory days have improved on an overall basis from 100 days in 2006. This reduction has decreased our exposure to metals price movements as well as increased capacity in our facilities to devote to higher margin products. These organizational and operating changes have improved our operating structure, working capital management and efficiency.

As a result of our initiatives, we have increased our financial flexibility and believe we have a favorable cost structure compared to many of our peers. This will provide significant operating leverage.

Extensive Breadth of Products and Services for Diverse Customer Base.

We carry a full range of over 75,000 products, including aluminum, carbon, stainless and alloy steels and a limited line of nickel and red metals. In addition, we provide a broad range of processing and fabrication services to meet the needs of our 40,000 customers and fulfill more than 1,000,000 orders per year. We also provide supply chain solutions, including just-in-time delivery, and value-added components to many original equipment manufacturers.

We believe our broad product mix and marketing approach provides customers with a one-stop shop solution few other service center companies are able to offer.

For the year ended December 31, 2012, no single customer accounted for more than 2% of our sales, and our top 10 customers accounted for less than 10% of sales.

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Strong Relationships with Suppliers.

We are among the largest purchasers of metals in North America and have long-term relationships with many of our North American suppliers. We believe we are frequently one of the largest customers of our suppliers and that concentrating our orders among a core group of suppliers is an effective method for obtaining favorable pricing and service. We believe we have the opportunity to further leverage this strength through continued focus on price and volume using an analytics-driven approach to procurement. In addition, we view our strategic suppliers as supply chain partners. Our coordinated effort focused on logistics, lead times, rolling schedules, and scrap return programs ultimately results in value-based buying that is advantageous for us. Metals producers worldwide are consolidating, and large, geographically diversified customers, such as Ryerson, are desirable partners for these larger suppliers. Our relationships with suppliers often provides us with access to metals when supply is constrained. Through our knowledge of the global metals marketplace and capabilities of specific mills we believe we have developed a global purchasing strategy that allows us to secure favorable prices across our product lines.

Experienced Management Team with Deep Industry Knowledge.

Our senior management team has extensive industry and operational experience and has been instrumental in optimizing and implementing our strategy in the last two years. Our senior management has an average of more than 20 years of experience in the metals or service center industries. The senior executive team s extensive experience in international markets and outside the service center industry provides perspective to drive profitable growth.

Our CEO, Mr. Michael Arnold, joined the Company in January 2011 and has 34 years of diversified industrial experience. Mr. Edward Lehner, who has been our CFO since August 2012, has 24 years of experience predominantly in the metals industry. Under their leadership, we have increased our focus on positioning the Company for growth and enhanced profitability.

Our Strategy

Expand Margins.

We are actively pursuing strategies to achieve increased gross margins. We believe this will allow our profitability to accelerate as volumes in our industry improve. Although the first nine months of net sales in 2013 decreased by 16.3% as compared to the first nine months of net sales in 2012, we have employed and continue to employ the initiatives below, which have resulted in an increase in our gross margins as a percentage of sales, excluding LIFO expense, by over 100 basis points, from 15.7% in Q3 2012 to 16.9% in Q3 2013. We have excluded LIFO expense from the gross margin as a percentage of sales metric in order to provide a means of comparison amongst our competitors who may not use the same basis of accounting for inventories.

Optimize Product Mix. We see significant opportunities to continue to improve our margins by increasing long and plate products supplied to our customers, as long and plate products typically generate higher margins than flat products. We have established regional long product inventory to provide a broad line of stainless, aluminum, carbon and alloy long products as well as the necessary processing equipment to meet demanding requirements of these customers. In addition, over the past two years, 45% of our capital expenditures have gone toward upgrading and adding plate and long processing capabilities throughout our operational footprint. We expect to continue to optimize product mix through these initiatives.

Optimize Customer Mix. We have increased our focus on serving a diversified group of industrial customers that value our customized processing services which we price on a transaction-by-transaction basis as opposed to larger volume program account customers who typically have fixed pricing arrangements over varying time periods. Our sales to customers using transactional pricing arrangements typically generate higher margins and require less working capital investment. We have re-evaluated and re-priced many of our lower margin program accounts which has resulted in an increase in our margins, as evidenced above.

Expand Value-added Processing Services. We seek to continue to improve our margins by complementing our products with first stage manufacturing and other processing capabilities that add value for our customers. Additionally, for certain customers we have assumed the management and responsibility for complex supply chains involving numerous suppliers, fabricators and processors. We leverage our capabilities to deliver the highest value proposition to our customers by providing a wide breadth of competitive products and services, as well as superior customer service and product quality.

Improve Supply Chain and Procurement Management. As a large purchaser of metals we continue to use analytic-driven processes to develop supply chains which lower our procured costs, shorten our lead times, improve our working capital management and decrease our exposure to commodity price fluctuations.

Improve Operating Efficiency.

We are committed to improving our operating capabilities through continuous business improvements and cost reductions. We have made, and continue to make, improvements in a variety of areas, including operations, sales, delivery, administration and working capital management. Furthermore, we continue to focus on better customer service and the hiring, retention and promotion of high performing employees as well as place greater emphasis on working capital efficiencies. In particular with respect to inventory, our goal of maintaining approximately 75-80 days of sales on hand reduces our exposure to metals prices and increases capacity in facilities to devote to higher margin products. Our streamlined organizational structure combines local decision making with regional and national sourcing to improve efficiency.

Pursue Profitable Growth Through Expansion and Value-Accretive Acquisitions.

We are focused on increasing our sales to existing customers, as well as expanding our customer base globally, but there can be no guarantee we will be able to expand. We expect to continue increasing revenue through a variety of sales initiatives and by targeting attractive markets.

In North America, we have expanded and continue to expand in markets that we believe are underserved. We opened seven new facilities since 2011 in Texas, Georgia, Iowa, Illinois, Utah and Mexico, and have expanded higher-margin plate fabrication or long-product capabilities at many existing locations, where we have observed an opportunity to generate attractive returns. We are continuously monitoring opportunities for further expansion across the United States, Canada and Mexico. We expect to leverage our expertise in North America and selectively expand our business in China and Brazil as well as additional high growth emerging markets.

Since 2010, we have completed five strategic acquisitions: Texas Steel Processing Inc., SFI-Gray Steel Inc., Singer Steel Company, Turret Steel and Açofran Aços e Metais Ltda. These acquisitions have provided various opportunities for long-term value creation through the expansion of our product and service capabilities, geographic reach, operational distribution network, end markets diversification, cross-selling opportunities and the addition of transactional-based customers. Although the Company does not have any current plans to engage in any specific acquisitions, we regularly evaluate potential acquisitions of service center companies that complement our existing customer base and product offerings, and plan to continue pursuing our disciplined approach to such acquisitions.

Maintain Flexible Capital Structure and Strong Liquidity Position.

Our management team is focused on maintaining a strong level of liquidity that will facilitate our plans to execute our various growth strategies. Throughout the economic downturn, we maintained liquidity in excess of $300 million. Liquidity as of September 30, 2013 was approximately $423 million, comprised of $319 million of availability under Ryerson s senior secured $1.35 billion asset-based revolving credit facility and foreign debt facilities, and $104 million of cash-on-hand and marketable securities. We have no financial maintenance covenants in our debt agreements unless availability under the Ryerson Credit Facility falls below $125 million.

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Substantially all of the proceeds from this offering will be used to further reduce our outstanding indebtedness. In addition, following the 2012 bond refinancing, there are no significant debt maturities until the maturity of the Ryerson Credit Facility, which occurs on the earlier of (a) April 3, 2018 or (b) August 16, 2017 (60 days prior to the scheduled maturity date of the 9% Senior Secured Notes due 2017 issued by Ryerson and its wholly owned subsidiary, Joseph T. Ryerson & Son Inc. (the 2017 Notes)), if the 2017 Notes are then outstanding.

Risk Factors

An investment in our common stock is subject to substantial risks and uncertainties. Before investing in our common stock, you should carefully consider the following, as well as the more detailed discussion of risk factors and other information included in this prospectus:

- although the financial markets are in a state of recovery, the economic downturn reduced both demand for our products and metals prices;

- the metals distribution business is very competitive and increased competition could reduce our gross margins and net income;

- we may not be able to sustain the annual cost savings realized as part of our cost reduction initiatives; and

- we may not be able to successfully consummate and complete the integration of future acquisitions, and if we are unable to do so, we may be unable to increase our growth rates.

Recent Developments

Stock Split

On , 2013, our Board of Directors approved a for 1.00 stock split of the Company s common stock to be effected prior to the closing of this offering. Our consolidated financial statements as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 give retroactive effect to the stock split.

The Sponsor

Platinum Equity, LLC (together with its affiliates, Platinum Equity) is a global acquisition firm headquartered in Beverly Hills, California with principal offices in New York, Boston and London. Since its founding in 1995, Platinum Equity has completed more than 145 acquisitions in a broad range of market sectors including packaging, technology, industrials, logistics, distribution, maintenance and service. Platinum Equity s current portfolio includes over 30 companies in a variety of different industries that serve customers around the world. Platinum Equity has a diversified capital base that includes the assets of its portfolio companies, which generated more than $15 billion in revenue in 2012, as well as capital commitments from institutional investors in private equity funds managed by the firm. Platinum Equity s M&A&O® (Mergers & Acquisitions & Operations) approach to investing focuses on acquiring businesses that need operational support to realize their full potential and can benefit from Platinum Equity s expertise in transition, integration and operations.

Joseph T. Ryerson & Son, Inc. (JT Ryerson), one of our subsidiaries, is party to a corporate advisory services agreement (the Services Agreement) with Platinum Advisors, an affiliate of Platinum. In connection with this offering, Platinum Advisors and JT Ryerson intend to terminate the Services Agreement, pursuant to which JT Ryerson will pay Platinum Advisors $ million as consideration for terminating the Services Agreement. We refer to this as the Services Agreement Termination. See Certain Relationships and Related Party Transactions Services Agreement. Upon the consummation of this offering, the Company and Platinum

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will enter into an amended and restated investor rights agreement (the Investor Rights Agreement) which will provide, among other things, that for so long as Platinum collectively beneficially owns (i) at least 30% of the voting power of the outstanding capital stock of the Company, Platinum will have the right to nominate for election to the board of directors of the Company no fewer than that number of directors that would constitute a majority of the number of directors if there were no vacancies on the board, (ii) at least 15% but less than 30% of the voting power of the outstanding capital stock of the Company, Platinum will have the right to nominate two directors and (iii) at least 5% but less than 15% of the voting power of the outstanding capital stock of the Company, Platinum will have the right to nominate one director. For additional information with respect to Platinum s rights pursuant to the Investor Rights Agreement, see Certain Relationships and Related Party Transactions Investor Rights Agreement.

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Corporate Structure

Our current corporate structure is made up as follows: Ryerson Holding, the issuer of the common stock offered hereby, owns all of the common stock of Ryerson Inc. and all of the membership interests of Rhombus JV Holdings, LLC. Ryerson Inc. owns, directly or indirectly, all of the common stock of the following entities: JT Ryerson; Ryerson Americas, Inc.; Ryerson International, Inc.; Ryerson Pan-Pacific LLC; J.M. Tull Metals Company, Inc.; RdM Holdings, Inc.; RCJV Holdings, Inc.; Ryerson Procurement Corporation; Ryerson International Material Management Services, Inc.; Ryerson International Trading, Inc.; Ryerson Canada, Inc.; Ryerson Metals de Mexico, S. de R.L. de C.V.; 862809 Ontario, Inc.; Leets Assurance, Ltd.; Integris Metals Mexicana, S.A. de C.V.; Servicios Empresariales Ryerson Tull, S.A. de C.V.; Servicios Corporativos RIM, S.A. de C.V.; Turret Holding Corporation; Turret Steel Industries, Inc.; Turret Steel Canada, ULC; Sunbelt-Turret Steel, Inc.; Ryerson Brasil Participacoes Ltda; Ryerson Holdings (Brazil), LLC; EPE LLC; Ryerson Canada Finance ULC; Imperial Trucking Company, LLC; Wilcox-Turret Cold Drawn, Inc.; and Ryerson Holdings (India) Pte Ltd. Platinum currently owns 99% of the capital stock of Ryerson Holding and will own approximately % of the capital stock following this offering. The chart below illustrates in summary form our material operating subsidiaries.

[1] Platinum refers to the following entities: Platinum Equity Capital Partners, L.P.; Platinum Equity Capital Partners-PF, L.P.; Platinum Equity Capital Partners-A, L.P.; Platinum Equity Capital Partners II, L.P.; Platinum Equity Capital Partners-PF II, L.P.; Platinum Equity Capital Partners-A II, L.P.; and Platinum Rhombus Principals, LLC. For additional detail regarding ownership by Platinum, see Principal and Selling Stockholders.

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Corporate Information

Ryerson Holding and Ryerson Inc. are each incorporated under the laws of the State of Delaware. Ryerson Holding was formed in July 2007. Our principal executive offices are located at 227 W. Monroe, 27th Floor, Chicago, Illinois 60606. Our telephone number is (312) 292-5000.

On January 1, 2006, Ryerson Inc. changed its name from Ryerson Tull, Inc. to Ryerson Inc. On January 4, 2010, Ryerson Holding changed its name from Rhombus Holding Corporation to Ryerson Holding Corporation. Our website is located at *www.ryerson.com*. **Our website and the information contained on the website or connected thereto will not be deemed to be incorporated into this prospectus and you should not rely on any such information in making your decision whether to purchase our securities.**

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The Offering

Issuer	Ryerson Holding Corporation.
Common stock offered by us	shares.
Underwriters over-allotment option to purchase additional common stock from the selling stockholders	Up to shares.
Common stock outstanding before this offering	5,000,000 shares.
Common stock to be outstanding immediately following this offering	shares.
Use of proceeds	We estimate that our net proceeds from this offering will be approximately $ million, assuming an initial public offering price of $ per share, the mid-point of the estimated initial public offering price range.

We intend to use the net proceeds to us from this offering to (i) redeem $ in aggregate principal amount of the 11.25% Senior Notes due 2018 issued by Ryerson and its wholly owned subsidiary Joseph T. Ryerson & Son Inc. (the 2018 Notes), (ii) repay approximately $ of the borrowings outstanding under our $1.35 billion revolving credit facility agreement that matures on the earlier of (a) April 3, 2018 or (b) August 16, 2017 (60 days prior to the scheduled maturity date of the 2017 Notes), if the 2017 Notes are then outstanding (as amended, the Ryerson Credit Facility), (iii) pay Platinum Advisors $ as consideration for terminating the Services Agreement, (iv) redeem up to $ in aggregate principal amount of the 9% Senior Secured Notes due 2017 issued by Ryerson and its wholly owned subsidiary Joseph T. Ryerson & Son Inc. (the 2017 Notes and together with the 2018 Notes, the 2017 and 2018 Notes) and (v) pay related transaction fees, expenses and premiums in connection with this offering, which we currently expect to equal approximately $22.0 million.

	If the over-allotment is exercised, we will not receive any proceeds from the sale of our common stock by the selling stockholders.
Risk factors	See Risk Factors on page 17 of this prospectus for a discussion of factors you should carefully consider before deciding to invest in our common stock.
Dividend policy	We do not anticipate declaring or paying any regular cash dividends on our common stock in the foreseeable future. Any payment of cash dividends on our common stock in the future will be at the discretion of our Board of Directors and will depend upon our results of operations, earnings, capital requirements, financial condition, future prospects, contractual restrictions, including under the Ryerson Credit Facility and our outstanding notes, and other factors deemed relevant by our Board of Directors.

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Proposed New York Stock Exchange symbol	RYI.
Directed share program	At our request, the underwriters have reserved up to 5% of the shares of common stock for sale at the initial public offering price to persons who are employees, officers, directors and other parties associated with us through a directed share program. The number of shares of common stock available for sale to the general public will be reduced by the number of directed shares purchased by participants in the program. Any directed shares not purchased will be offered by the underwriters to the general public on the same basis as all other shares of common stock offered. We have agreed to indemnify the underwriters against certain liabilities and expenses, including liabilities under the Securities Act, in connection with the sales of the directed shares. Individuals who purchase shares in excess of $1,000,000 in the directed share program will be subject to a 25-day lock-up period, except that any of our executive officers or directors or any selling stockholders who purchase shares in the directed share program will remain subject to the 180-day lock-up period from the date of this prospectus, as described in Underwriting No Sales of Similar Securities.

The number of shares to be outstanding after this offering is based on 5,000,000 shares of common stock outstanding immediately before this offering and the shares of common stock being sold by us in this offering, and assumes no exercise by the underwriters of their option to purchase shares of our common stock in this offering to cover over-allotments, if any. The number of shares to be outstanding after this offering excludes shares of common stock reserved for future grants under our stock incentive plan assuming such plan is adopted in connection with this offering.

Unless we specifically state otherwise, the information in this prospectus assumes:

- an initial public offering price of $ per share, the mid-point of the offering range set forth on the cover page of this prospectus;
- the underwriters do not exercise their over-allotment option; and
- a for 1.00 stock split that will occur prior to the closing of this offering.

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Summary Historical Consolidated Financial and Other Data

The following table presents our summary historical consolidated financial data, as of the dates and for the periods indicated. Our summary historical consolidated statements of operations data for the years ended December 31, 2010, 2011 and 2012 and the summary historical balance sheet data as of December 31, 2011 and 2012 have been derived from our audited consolidated financial statements included elsewhere in this prospectus.

Our selected historical consolidated financial data as of September 30, 2012 and 2013 and for the nine months ended September 30, 2012 and 2013 have been derived from our unaudited consolidated financial statements included elsewhere in this prospectus. The September 30, 2012 and 2013 unaudited financial statements have been prepared on a basis consistent with our audited consolidated financial statements and reflect all adjustments, consisting of normal recurring adjustments that are, in the opinion of management, necessary for a fair presentation of the financial position and results of operations for the periods presented. The results of any interim period are not necessarily indicative of the results that may be expected for any other interim period or for the full fiscal year, and the historical results set forth below do not necessarily indicate results expected for any future period.

You should read the summary financial and other data set forth below along with the sections in this prospectus entitled Use of Proceeds, Selected Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related notes included elsewhere in this prospectus. The share and per share information presented below has been adjusted to give effect to the for 1.00 stock split that will occur immediately prior to the closing of this offering.

	Year Ended December 31,			Nine Months Ended September 30,	
	2010	2011	2012	2012	2013
	($ in millions)				
Statements of Operations Data:					
Net sales	$ 3,895.5	$ 4,729.8	$ 4,024.7	$ 3,174.4	$ 2,657.8
Cost of materials sold	3,355.7	4,071.0	3,315.1	2,619.1	2,188.4
Gross profit	539.8	658.8	709.6	555.3	469.4
Warehousing, selling, general and administrative	506.9	539.7	508.9	389.9	363.2
Restructuring and other charges	12.0	11.1	1.1		2.1
Gain on insurance settlement	(2.6)				
Impairment charges on fixed assets and goodwill	1.4	9.3	1.0	0.9	8.8
Pension and other postretirement benefits curtailment (gain) loss	2.0		(1.7)		
Operating profit	20.1	98.7	200.3	164.5	95.3
Other income and (expense), net (1)	(3.2)	4.6	(33.5)	(1.0)	2.1
Interest and other expense on debt (2)	(107.5)	(123.1)	(126.5)	(97.6)	(83.3)
Income (loss) before income taxes	(90.6)	(19.8)	40.3	65.9	14.1
Provision (benefit) for income taxes (3)	13.1	(11.0)	(5.5)	9.6	5.9
Net income (loss)	(103.7)	(8.8)	45.8	56.3	8.2
Less: Net income (loss) attributable to noncontrolling interest	0.3	(0.7)	(1.3)	(0.7)	(0.9)
Net income (loss) attributable to Ryerson Holding Corporation	$ (104.0)	$ (8.1)	$ 47.1	$ 57.0	$ 9.1

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	Year Ended December 31, 2010	2011	2012	Nine Months Ended September 30, 2012	2013
	($ in millions, except per share data)				
Earnings (loss) per share of common stock:					
Basic earnings (loss) per share	$ (20.80)	$ (1.62)	$ 9.41	$ 11.41	$ 1.82
Diluted earnings (loss) per share	$ (20.80)	$ (1.62)	$ 9.41	$ 11.41	$ 1.82
Weighted average shares outstanding Basic	5.0	5.0	5.0	5.0	5.0
Weighted average shares outstanding Diluted	5.0	5.0	5.0	5.0	5.0
Balance Sheet Data (at period end):					
Cash and cash equivalents	$ 62.6	$ 61.7	$ 71.2	$ 54.4	$ 81.1
Restricted cash	15.6	5.3	3.9	4.3	4.6
Inventory	783.4	732.4	741.5	779.8	702.8
Working capital	858.8	806.6	796.7	801.4	738.9
Property, plant and equipment, net	479.2	479.7	472.3	478.9	450.4
Total assets	2,053.5	2,058.4	1,954.1	2,056.4	1,922.5
Long-term debt, including current maturities	1,211.3	1,316.2	1,305.4	1,260.1	1,240.1
Other Financial Data:					
Cash flows provided by (used in) operations	$ (198.7)	$ 54.5	$ 186.5	$ 86.1	$ 88.0
Cash flows used in investing activities	(44.4)	(115.0)	(35.3)	(29.5)	(12.9)
Cash flows provided by (used in) financing activities	185.1	57.9	(143.4)	(65.5)	(62.5)
Capital expenditures	27.0	47.0	40.8	32.0	16.5
Depreciation and amortization	38.4	43.0	47.0	34.6	34.7
EBITDA (4)	55.0	147.0	215.1	198.8	133.0
Adjusted EBITDA (4)	81.1	174.5	264.7	212.7	154.7
Adjusted EBITDA, excluding LIFO (4)	133.5	223.1	201.6	166.3	128.1
Ratio of Tangible Assets to Total Net Debt (5)	1.5x	1.4x	1.3x	1.4x	1.4x
Volume and Per Ton Data:					
Tons shipped (000)	2,252	2,433	2,149	1,671	1,559
Average number of employees	4,126	4,236	4,021	4,061	3,888
Tons shipped per employee	546	574	534	411	401
Average selling price per ton	$ 1,730	$ 1,944	$ 1,873	$ 1,900	$ 1,705
Gross profit per ton	240	271	330	332	301
Operating profit per ton	9	41	93	98	61

(1) The year ended December 31, 2010 includes $2.6 million of foreign exchange losses related to the repayment of a long-term loan to our Canadian operations. The year ended December 31, 2011 includes a $5.8 million gain on bargain purchase related to our Singer acquisition. The year ended December 31, 2012 includes a $32.8 million loss on the redemption of the Ryerson Notes and Ryerson Holding Notes.

(2) The year ended December 31, 2011 includes a $1.1 million write off of debt issuance costs associated with our prior credit facility upon entering into an amended revolving credit facility on March 14, 2011.

(3) The year ended December 31, 2011 includes income tax benefits of $18.0 million relating to the purchase accounting impact of the Turret and Singer acquisitions. The year ended December 31, 2012 includes an income tax benefit of $15.2 million related to the release of valuation allowance associated with certain state deferred tax assets.

(4) EBITDA, for the periods presented, represents net income before interest and other expense on debt, provision for income taxes, depreciation and amortization. Adjusted EBITDA gives further effect to, among other things, loss on retirement of debt, impairment charges on fixed assets and goodwill, reorganization expenses and the payment of management fees. We believe that the presentation of EBITDA, Adjusted EBITDA and Adjusted EBITDA, excluding LIFO expense (income) provides useful information to investors regarding our operational performance because they enhance an investor s overall understanding of our core financial performance and provide a basis of comparison of results between current, past and future periods. We also disclose the metric Adjusted EBITDA, excluding LIFO expense (income), to provide a means of comparison amongst our competitors who may not use the same basis of accounting for inventories. EBITDA, Adjusted EBITDA and Adjusted EBITDA, excluding LIFO expense (income) are three of the primary metrics management uses for planning and forecasting in future periods, including trending and analyzing the core operating performance of our business without the effect of U.S. generally

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accepted accounting principles, or GAAP, expenses, revenues and gains (losses) that are unrelated to the day to day performance of our business. We also establish compensation programs for our executive management and regional employees that are based upon the achievement of pre-established EBITDA, Adjusted EBITDA and Adjusted EBITDA, excluding LIFO expense (income) targets. We also use EBITDA, Adjusted EBITDA and Adjusted EBITDA, excluding LIFO expense (income) to benchmark our operating performance to that of our competitors. EBITDA, Adjusted EBITDA and Adjusted EBITDA, excluding LIFO expense (income) do not represent, and should not be used as a substitute for, net income or cash flows from operations as determined in accordance with generally accepted accounting principles, and neither EBITDA, Adjusted EBITDA and Adjusted EBITDA, excluding LIFO expense (income) is necessarily an indication of whether cash flow will be sufficient to fund our cash requirements. Our definitions of EBITDA, Adjusted EBITDA and Adjusted EBITDA, excluding LIFO expense (income) may differ from that of other companies. Set forth below is the reconciliation of net income to EBITDA, as further adjusted to Adjusted EBITDA and Adjusted EBITDA, excluding LIFO expense (income).

	Year Ended December 31,			Nine Months Ended September 30,	
	2010	2011	2012	2012	2013
			($ in millions)		
Net income (loss) attributable to Ryerson Holding	$ (104.0)	$ (8.1)	$ 47.1	$ 57.0	$ 9.1
Interest and other expense on debt	107.5	123.1	126.5	97.6	83.3
Provision (benefit) for income taxes	13.1	(11.0)	(5.5)	9.6	5.9
Depreciation and amortization	38.4	43.0	47.0	34.6	34.7
EBITDA	55.0	147.0	215.1	198.8	133.0
Reorganization	19.1	17.8	5.8	4.7	8.5
Advisory service fee	5.0	5.0	5.0	3.8	3.8
Loss on retirement of debt			32.8		
Foreign currency transaction (gains) losses	2.7	0.8	1.5	1.6	(1.6)
Gain on insurance settlement	(2.6)				
Impairment charges on fixed assets and goodwill	1.4	9.3	1.0	0.9	8.8
Gain on bargain purchase		(5.8)			
Purchase consideration			4.3	3.5	2.7
Other adjustments	0.5	0.4	(0.8)	(0.6)	(0.5)
Adjusted EBITDA	81.1	174.5	264.7	212.7	154.7
LIFO expense (income)	52.4	48.6	(63.1)	(46.4)	(26.6)
Adjusted EBITDA, excluding LIFO expense (income)	$ 133.5	$ 223.1	$ 201.6	$ 166.3	$ 128.1

(5) The table below sets forth the inputs used for the calculations of the ratio of tangible assets to total net debt for the years ended December 31, 2010, 2011 and 2012 and nine months ended September 30, 2012 and 2013.

	Year ended December 31,			Nine Months Ended September 30,	
	2010	2011	2012	2012	2013
			($ in millions)		
Receivables less provision for allowances, claims and doubtful accounts	$ 497.9	$ 513.9	$ 394.1	$ 484.4	$ 420.2
Inventories	783.4	732.4	741.5	779.8	702.8
Assets held for sale	14.3	10.0	3.6	3.7	4.5
Property, plant and equipment, net of accumulated depreciation	479.2	479.7	472.3	478.9	450.4
Tangible Assets	$ 1,774.8	$ 1,736.0	$ 1,611.5	$ 1,746.8	$ 1,577.9

Long-term debt, including current maturities	$ 1,211.3	$ 1,316.2	$ 1,305.4	$ 1,260.1	$ 1,240.1
Less cash and cash equivalents	(62.6)	(61.7)	(71.2)	(54.4)	(81.1)
Total Net Debt	$ 1,148.7	$ 1,254.5	$ 1,234.2	$ 1,205.7	$ 1,159.0
Ratio of Tangible Assets to Total Net Debt	1.5x	1.4x	1.3x	1.4x	1.4x

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RISK FACTORS

Investing in our common stock involves a high degree of risk. You should carefully consider the risks described below, together with the other information contained in this prospectus, before making your decision to invest in shares of our common stock. We cannot assure you that any of the events discussed in the risk factors below will not occur. These risks could have a material and adverse impact on our business, results of operations, financial condition and cash flows. If that were to happen, the trading price of our common stock could decline, and you could lose all or part of your investment.

Risks Relating to Our Business

We service industries that are highly cyclical, and any downturn in our customers industries could reduce our sales and profitability. The economic downturn has reduced demand for our products and may continue to reduce demand until an economic recovery.

Many of our products are sold to industries that experience significant fluctuations in demand based on economic conditions, energy prices, seasonality, consumer demand and other factors beyond our control. These industries include manufacturing, electrical products and transportation. We do not expect the cyclical nature of our industry to change.

The U.S. economy entered an economic recession in December 2007, which spread to many global markets in 2008 and 2009 and affected Ryerson and other metals service centers. Beginning in late 2008 and continuing through 2013, the metals industry, including Ryerson and other service centers, felt additional effects of the global economic crisis and recovery thereto and the impact of the credit market disruption. These events contributed to a rapid decline in both demand for our products and pricing levels for those products. The Company has implemented a number of actions to conserve cash, reduce costs and strengthen its competitiveness, including curtailing non-critical capital expenditures, initiating headcount reductions and reductions of certain employee benefits, among other actions. However, there can be no assurance that these actions, or any others that the Company may take in response to further deterioration in economic and financial conditions, will be sufficient.

The volatility of the market could result in a material impairment of goodwill.

We evaluate goodwill annually on October 1 and whenever events or changes in circumstances indicate potential impairment. Events or changes in circumstances that could trigger an impairment review include significant underperformance relative to our historical or projected future operating results, significant changes in the manner or the use of our assets or the strategy for our overall business, and significant negative industry or economic trends. We test for impairment of goodwill by calculating the fair value of a reporting unit using an average of an income approach based on discounted future cash flows and a market approach at the date of valuation. Under the discounted cash flow method, the fair value of each reporting unit is estimated based on expected future economic benefits discounted to a present value at a rate of return commensurate with the risk associated with the investment. Projected cash flows are discounted to present value using an estimated weighted average cost of capital, which considers both returns to equity and debt investors. Significant changes in any one of the assumptions made as part of our analysis, which could occur as a result of actual events, or further declines in the market conditions for our products, could significantly impact our impairment analysis. An impairment charge, if incurred, could be material.

The metals distribution business is very competitive and increased competition could reduce our revenues and gross margins.

The principal markets that we serve are highly competitive. The metals distribution industry is fragmented and competitive, consisting of a large number of small companies and a few relatively large companies. Competition is based principally on price, service, quality, production capabilities, inventory availability and timely delivery. Competition in the various markets in which we participate comes from companies of various sizes, some of which have greater financial resources than we have and some of which have more established brand names in the local markets served by us. Increased competition could reduce our market share, force us to lower our prices or to offer increased services at a higher cost, which could reduce our profitability.

The economic downturn has reduced metals prices. Though prices have risen since the onset of the economic downturn, we cannot assure you that prices will continue to rise. Changing metals prices may have a significant impact on our liquidity, net sales, gross margins, operating income and net income.

The metals industry as a whole is cyclical and, at times, pricing and availability of metal can be volatile due to numerous factors beyond our control, including general domestic and international economic conditions, labor costs, sales levels, competition, levels of inventory held by other metals service centers, consolidation of metals producers, higher raw material costs for the producers of metals, import duties and tariffs and currency exchange rates. This volatility can significantly affect the availability and cost of materials for us.

We, like many other metals service centers, maintain substantial inventories of metal to accommodate the short lead times and just-in-time delivery requirements of our customers. Accordingly, we purchase metals in an effort to maintain our inventory at levels that we believe to be appropriate to satisfy the anticipated needs of our customers based upon historic buying practices, contracts with customers and market conditions. When metals prices decline, as they did in 2008 and 2009, customer demands for lower prices and our competitors responses to those demands could result in lower sale prices and, consequently, lower margins as we use existing metals inventory. Notwithstanding recent price increases, metals prices may decline, and declines in those prices or further reductions in sales volumes could adversely impact our ability to maintain our liquidity and to remain in compliance with certain financial covenants under the Ryerson Credit Facility, as well as result in us incurring inventory or goodwill impairment charges. Changing metals prices therefore could significantly impact our liquidity, net sales, gross margins, operating income and net income.

We have a substantial amount of indebtedness, which could adversely affect our financial position and prevent us from fulfilling our obligations.

We currently have a substantial amount of indebtedness, including, as of September 30, 2013, $600.0 million outstanding under our 2017 Notes and $300.0 million outstanding under our 2018 Notes, and may incur additional indebtedness in the future. As of September 30, 2013, after giving effect to this offering and the application of net proceeds from this offering our total indebtedness would have been approximately $ million and we would have had approximately $ million of unused capacity under the Ryerson Credit Facility. Our substantial indebtedness may:

- make it difficult for us to satisfy our financial obligations, including making scheduled principal and interest payments on our outstanding notes and our other indebtedness;
- limit our ability to borrow additional funds for working capital, capital expenditures, acquisitions and general corporate and other purposes;
- limit our ability to use our cash flow or obtain additional financing for future working capital, capital expenditures, acquisitions or other general corporate purposes;
- require us to use a substantial portion of our cash flow from operations to make debt service payments;
- limit our flexibility to plan for, or react to, changes in our business and industry;
- place us at a competitive disadvantage compared to our less leveraged competitors; and

- increase our vulnerability to the impact of adverse economic and industry conditions.

We may also incur additional indebtedness in the future. The terms of the Ryerson Credit Facility and the indentures governing our outstanding notes restrict but do not prohibit us from doing so, and the indebtedness incurred in compliance with these restrictions could be substantial. If new indebtedness is added to our current debt levels, the related risks that we now face could intensify.

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The covenants in the Ryerson Credit Facility and the indentures governing our outstanding notes impose, and covenants contained in agreements governing indebtedness we incur in the future may impose, restrictions that may limit our operating and financial flexibility.

The Ryerson Credit Facility and the indentures governing our outstanding notes contain a number of significant restrictions and covenants that limit our ability and the ability of our restricted subsidiaries, including Ryerson Inc., to:

- incur additional debt;
- pay dividends on our capital stock or repurchase our capital stock;
- make certain investments or other restricted payments;
- create liens or use assets as security in other transactions;
- merge, consolidate or transfer or dispose of substantially all of our assets; and
- engage in transactions with affiliates.

The terms of the Ryerson Credit Facility require that, in the event availability under the facility declines to a certain level, we maintain a minimum fixed charge coverage ratio at the end of each fiscal quarter. Total credit availability is limited by the amount of eligible accounts receivable and inventory pledged as collateral under the agreement insofar as the Company is subject to a borrowing base comprised of the aggregate of these two amounts, less applicable reserves. As of September 30, 2013, total credit availability was $291 million based upon eligible accounts receivable and inventory pledged as collateral.

Additionally, subject to certain exceptions, the indentures governing the outstanding notes restrict Ryerson s ability to pay us dividends to the extent of 50% of future net income, once prior losses are offset. Future net income is defined in the indenture governing the notes as net income adjusted for, among other things, the inclusion of dividends from joint ventures actually received in cash by Ryerson, and the exclusion of: (i) all extraordinary gains or losses; (ii) a certain portion of net income allocable to minority interest in unconsolidated persons or investments in unrestricted subsidiaries; (iii) gains or losses in respect of any asset sale on an after tax basis; (iv) the net income from any disposed or discontinued operations or any net gains or losses on disposed or discontinued operations, on an after-tax basis; (v) any gain or loss realized as a result of the cumulative effect of a change in accounting principles; (vi) any fees and expenses paid in connection with the issuance of the notes; (vii) non-cash compensation expense incurred with any issuance of equity interest to an employee; and (viii) any net after-tax gains or losses attributable to the early extinguishment of debt. Our future indebtedness may contain covenants more restrictive in certain respects than the restrictions contained in the Ryerson Credit Facility and the indentures governing the notes. Operating results below current levels or other adverse factors, including a significant increase in interest rates, could result in our being unable to comply with financial covenants that are contained in the Ryerson Credit Facility or that may be contained in any future indebtedness. In addition, complying with these covenants may also cause us to take actions that are not favorable to holders of our notes and may make it more difficult for us to successfully execute our business strategy and compete against companies that are not subject to such restrictions.

We may not be able to generate sufficient cash to service all of our indebtedness.

Our ability to make payments on our indebtedness depends on our ability to generate cash in the future. Our outstanding notes, the Ryerson Credit Facility and our other outstanding indebtedness are expected to account for significant cash interest expenses. Accordingly, we will have to generate significant cash flows from operations to meet our debt service requirements. If we do not generate sufficient cash flow to meet our debt service and working capital requirements, we may be required to sell assets, seek additional capital, reduce capital expenditures, restructure or refinance all or a portion of our existing indebtedness, or seek additional financing. Moreover, insufficient cash flow may make it more difficult for us to obtain financing on terms that are acceptable to us, or at all. Furthermore, Platinum has no obligation to provide us with debt or equity financing and we therefore may be unable to generate sufficient cash to service all of our indebtedness.

Because a portion of our indebtedness bears interest at rates that fluctuate with changes in certain prevailing short-term interest rates, we are vulnerable to interest rate increases.

A portion of our indebtedness, including the Ryerson Credit Facility, bears interest at rates that fluctuate with changes in certain short-term prevailing interest rates. As of September 30, 2013, we had approximately $318.5 million of outstanding borrowings under the Ryerson Credit Facility, with an additional $291 million available for borrowing under such facility. Assuming a consistent level of debt, a 100 basis point change in the interest rate on our floating rate debt effective from the beginning of the year would increase or decrease our interest expense under the Ryerson Credit Facility by approximately $3.6 million on an annual basis. If interest rates increase dramatically, we could be unable to service our debt which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

We may not be able to successfully consummate and complete the integration of future acquisitions, and if we are unable to do so, we may be unable to increase our growth rates.

We have grown through a combination of internal expansion, acquisitions and joint ventures. We intend to continue to grow through selective acquisitions, but we may not be able to identify appropriate acquisition candidates, obtain financing on satisfactory terms, consummate acquisitions or integrate acquired businesses effectively and profitably into our existing operations. Restrictions contained in the agreements governing our notes, the Ryerson Credit Facility or our other existing or future debt may also inhibit our ability to make certain investments, including acquisitions and participations in joint ventures.

Our future success will depend on our ability to complete the integration of these future acquisitions successfully into our operations. After any acquisition, customers may choose to diversify their supply chains to reduce reliance on a single supplier for a portion of their metals needs. We may not be able to retain all of our and an acquisition s customers, which may adversely affect our business and sales. Integrating acquisitions, particularly large acquisitions, requires us to enhance our operational and financial systems and employ additional qualified personnel, management and financial resources, and may adversely affect our business by diverting management away from day-to-day operations. Further, failure to successfully integrate acquisitions may adversely affect our profitability by creating significant operating inefficiencies that could increase our operating expenses as a percentage of sales and reduce our operating income. In addition, we may not realize expected cost savings from acquisitions, which may also adversely affect our profitability.

We may not be able to retain or expand our customer base if the North American manufacturing industry continues to erode through moving offshore or through acquisition and merger or consolidation activity in our customers industries.

Our customer base primarily includes manufacturing and industrial firms. Some of our customers operate in industries that are undergoing consolidation through acquisition and merger activity; some are considering or have considered relocating production operations overseas or outsourcing particular functions overseas; and some customers have closed as they were unable to compete successfully with overseas competitors. Our facilities are predominately located in the United States and Canada. To the extent that our customers cease U.S. operations, relocate or move operations overseas to regions in which we do not have a presence, we could lose their business. Acquirers of manufacturing and industrial firms may have suppliers of choice that do not include us, which could impact our customer base and market share.

Certain of our operations are located outside of the United States, which subjects us to risks associated with international activities.

Certain of our operations are located outside of the United States, primarily in Canada, China, Mexico and Brazil. We are subject to the Foreign Corrupt Practices Act (FCPA), which generally prohibits U.S. companies and their intermediaries from making corrupt payments or otherwise corruptly giving any other thing of value to foreign officials for the purpose of obtaining or keeping business or otherwise obtaining favorable treatment, and requires companies to maintain adequate record-keeping and internal accounting practices. The FCPA applies to covered companies, individual directors, officers, employees and agents. Under the FCPA, U.S. companies may be held liable for some actions taken by strategic or local partners or representatives. If we or our intermediaries fail to comply with the requirements of the FCPA, governmental authorities in the United States could seek to impose civil and/or criminal penalties.

The Chinese government exerts substantial influence over the manner in which we must conduct our business activities, particularly with regards to the land our facilities are located on.

The Chinese government has exercised and continues to exercise substantial control over the Chinese economy through regulation and state ownership. Our ability to operate in China may be harmed by changes in its laws and regulations, including those relating to taxation, import and export tariffs, environmental regulations, land use rights, property and other matters. We believe that our operations in China are in material compliance with all applicable legal and regulatory requirements. However, the central or local governments of the jurisdictions in which we operate may impose new, stricter regulations or interpretations of existing regulations that would require additional expenditures and efforts on our part to ensure our compliance with such regulations or interpretations. Moreover, the Chinese court system does not provide the same property and contract right guarantees as do courts in the United States and, accordingly, disputes may be protracted and resolution of claims may result in significant economic loss.

Additionally, although in recent years the Chinese government has implemented measures emphasizing the utilization of market forces for economic reform, there is no private ownership of land in China and all land ownership is held by the government of China, its agencies, and collectives, which issue land use rights that are generally renewable. We lease the land where our Chinese facilities are located from the Chinese government. Although we believe our relationship with the Chinese government is sound, if the Chinese government decided to terminate our land use rights agreements, our assets could become impaired and our ability to meet customer orders could be impacted.

Operating results experience seasonal fluctuations.

A portion of our customers experience seasonal slowdowns. Our sales in the months of July, November and December traditionally have been lower than in other months because of a reduced number of shipping days and holiday or vacation closures for some customers. Consequently, our sales in the first two quarters of the year are usually higher than in the third and fourth quarters.

Damage to our information technology infrastructure could harm our business.

The unavailability of any of our computer-based systems for any significant period of time could have a material adverse effect on our operations. In particular, our ability to manage inventory levels successfully largely depends on the efficient operation of our computer hardware and software systems. We use management information systems to track inventory information at individual facilities, communicate customer information and aggregate daily sales, margin and promotional information. Difficulties associated with upgrades, installations of major software or hardware, and integration with new systems could have a material adverse effect on results of operations. We will be required to expend substantial resources to integrate our information systems with the systems of companies we have acquired. The integration of these systems may disrupt our business or lead to operating inefficiencies. In addition, these systems are vulnerable to, among other things, damage or interruption from fire, flood, tornado and other natural disasters, power loss, computer system and network failures, operator negligence, physical and electronic loss of data, or security breaches and computer viruses.

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Any significant work stoppages can harm our business.

As of September 30, 2013, we employed approximately 3,300 persons in North America, 400 persons in China, and 50 persons in Brazil. Our North American workforce was comprised of approximately 1,600 office employees and approximately 1,700 plant employees. Twenty-nine percent of our plant employees were members of various unions, including the United Steel Workers and the International Brotherhood of Teamsters. Our relationship with the various unions has generally been good.

Ten contracts covering approximately 312 persons were scheduled to expire in 2011. One of these contracts, which covered 59 employees, was not renewed due to facility closure. Eight of these contracts were successfully negotiated in 2011 and the remaining contract covering 60 employees was extended and successfully negotiated in 2012. Six contracts covering approximately 258 employees were scheduled to expire in 2012. We reached agreement on the renewal of all six contracts in 2012. One contract covering 11 employees is scheduled to expire in 2013. Negotiations are scheduled to begin in December 2013. Eight contracts covering approximately 170 employees are scheduled to expire in 2014.

Certain employee retirement benefit plans are underfunded and the actual cost of those benefits could exceed current estimates, which would require us to fund the shortfall.

As of December 31, 2012, our pension plan had an unfunded liability of $370 million. Our actual costs for benefits required to be paid may exceed those projected and future actuarial assessments to the extent that those costs exceed the current assessment. Under those circumstances, the adjustments required to be made to our recorded liability for these benefits could have a material adverse effect on our results of operations and financial condition and cash payments to fund these plans could have a material adverse effect on our cash flows. We may be required to make substantial future contributions to improve the plan s funded status.

Future funding for postretirement employee benefits other than pensions also may require substantial payments from current cash flow.

We provide postretirement life insurance and medical benefits to eligible retired employees. Our unfunded postretirement benefit obligation as of December 31, 2012 was $130 million. Our actual costs for benefits required to be paid may exceed those projected and future actuarial assessments to the extent that those costs exceed the current assessment. Under those circumstances, adjustments will be required to be made to our recorded liability for these benefits.

Any prolonged disruption of our processing centers could harm our business.

We have dedicated processing centers that permit us to produce standardized products in large volumes while maintaining low operating costs. We may suffer prolonged disruption in the operations of any of these facilities, whether due to labor or technical difficulties, destruction or damage to any of the facilities or otherwise.

If we are unable to retain and attract management and key personnel, it may adversely affect our business.

We believe that our success is due, in part, to our experienced management team. Losing the services of one or more members of our management team could adversely affect our business and possibly prevent us from improving our operational, financial and information management systems and controls. In the future, we may need to retain and hire additional qualified sales, marketing, administrative, operating and technical personnel, and to train and manage new personnel. Our ability to implement our business plan is dependent on our ability to retain and hire a large number of qualified employees each year.

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Our existing international operations and potential joint ventures may cause us to incur costs and risks that may distract management from effectively operating our North American business, and such operations or joint ventures may not be profitable.

We maintain foreign operations in Canada, China, Mexico and Brazil. International operations are subject to certain risks inherent in conducting business in, and with, foreign countries, including price controls, exchange controls, export controls, economic sanctions, duties, tariffs, limitations on participation in local enterprises, nationalization, expropriation and other governmental action, and changes in currency exchange rates. While we believe that our current arrangements with local partners provide us with experienced business partners in foreign countries, events or issues, including disagreements with our partners, may occur that require attention of our senior executives and may result in expenses or losses that erode the profitability of our foreign operations or cause our capital investments abroad to be unprofitable.

Lead time and the cost of our products could increase if we were to lose one of our primary suppliers.

If, for any reason, our primary suppliers of aluminum, carbon steel, stainless steel or other metals should curtail or discontinue their delivery of such metals in the quantities needed and at prices that are competitive, our business could suffer. The number of available suppliers could be reduced by factors such as industry consolidation and bankruptcies affecting steel and metal producers. For the year ended December 31, 2012, our top 25 suppliers represented approximately 75% of our purchases. We could be significantly and adversely affected if delivery were disrupted from a major supplier. If, in the future, we were unable to obtain sufficient amounts of the necessary metals at competitive prices and on a timely basis from our traditional suppliers, we may not be able to obtain such metals from alternative sources at competitive prices to meet our delivery schedules, which could have a material adverse effect on our sales and profitability.

We could incur substantial costs related to environmental, health and safety laws.

Our operations are subject to increasingly stringent environmental, health and safety laws. These include laws that impose limitations on the discharge of pollutants into the air and water and establish standards for the treatment, storage and disposal of regulated materials and the investigation and remediation of contaminated soil, surface water and groundwater. Failure to maintain or achieve compliance with these laws or with the permits required for our operations could result in substantial increases in operating costs and capital expenditures. In addition, we may be subject to fines and civil or criminal sanctions, third party claims for property damage or personal injury, worker s compensation or personal injury claims, cleanup costs or temporary or permanent discontinuance of operations. Certain of our facilities are located in industrial areas, have a history of heavy industrial use and have been in operation for many years and, over time, we and other predecessor operators of these facilities have generated, used, handled and disposed of hazardous and other regulated wastes. Environmental liabilities could exist, including cleanup obligations at these facilities or at off-site locations where materials from our operations were disposed of, which could result in future expenditures that cannot be currently quantified and which could have a material adverse effect on our financial position, results of operations or cash flows. Such liabilities may be imposed without regard to fault or the legality of a party s conduct and may, in certain circumstances, be joint and several. Future changes to environmental, health and safety laws, including those related to climate change, could result in material liabilities and costs, constrain operations or make such operations more costly for us, our suppliers and our customers. In October 2011, the United States Environmental Protection Agency named us as one of more than 100 businesses that may be a potentially responsible party for the Portland Harbor Superfund Site. We do not currently have sufficient information available to us to determine the total cost of any required investigation or remediation of the Portland Harbor site and, therefore, management cannot predict the ultimate outcome of this matter or estimate a range of potential loss at this time.

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New regulations related to conflict-free minerals may force us to incur additional expenses and place us at a competitive disadvantage.

On August 22, 2012, under the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the Dodd-Frank Act), the SEC adopted new requirements for reporting companies that use certain minerals and metals, known as conflict minerals , in their products, whether or not these products are manufactured by third parties. These requirements will require companies to diligence, disclose and report whether or not such minerals originate from the Democratic Republic of Congo and adjoining countries. Since our supply chain is complex, we may not be able to conclusively verify the origins for all metals used in our products and we may face reputational challenges with our customers. Additionally, as there may be only a limited number of suppliers offering conflict free metals, we cannot be sure that we will be able to obtain necessary metals from such suppliers in sufficient quantities or at competitive prices. Accordingly, we could incur significant cost related to the compliance process, including potential difficulty or added costs in satisfying the disclosure requirements. Moreover, we may encounter challenges to satisfy those customers who require that all of the components of our products be certified as conflict free which could place us at a competitive disadvantage if we are unable to do so.

We are subject to litigation that could strain our resources and distract management.

From time to time, we are involved in a variety of claims, lawsuits and other disputes arising in the ordinary course of business. These suits concern issues including product liability, contract disputes, employee-related matters and personal injury matters. It is not feasible to predict the outcome of all pending suits and claims, and the ultimate resolution of these matters as well as future lawsuits could have a material adverse effect on our business, financial condition, results of operations or cash flows or reputation.

We may face product liability claims that are costly and create adverse publicity.

If any of the products that we sell cause harm to any of our customers, we could be exposed to product liability lawsuits. If we were found liable under product liability claims, we could be required to pay substantial monetary damages. Further, even if we successfully defended ourself against this type of claim, we could be forced to spend a substantial amount of money in litigation expenses, our management could be required to spend valuable time in the defense against these claims and our reputation could suffer.

Our ability to use our net operating loss carryforwards and certain other tax attributes may be limited.

As of September 30, 2013, we had U.S. federal net operating loss carryforwards totaling approximately $162 million, which expire between December 31, 2030 and December 31, 2031. Under Section 382 of the Internal Revenue Code of 1986, as amended, if a corporation undergoes an ownership change, the corporation s ability to use its pre-change net operating loss carryforwards and certain other pre-change tax attributes to offset its post-change income may be limited significantly. In general, an ownership change will occur if there is a cumulative change in our ownership by 5-percent shareholders that exceeds 50 percentage points over a rolling three-year period. It is not expected that the offering will result in an ownership change. However, because the potential existence and amount of our 5-percent shareholders, if any, resulting from the offering is not within our control, there is no assurance that the offering will not result in an ownership change. Moreover, even if an ownership change does not result from the offering, subsequent events over which we will have little or no control (including changes in the direct and indirect ownership of our 5-percent shareholders) may cause us to experience an ownership change in the near future. An ownership change could significantly limit the future use of our pre-change tax attributes and thereby significantly increase our future tax liabilities.

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Our risk management strategies may result in losses.

From time to time, we may use fixed-price and/or fixed-volume supplier contracts to offset contracts with customers. Additionally, we may use foreign exchange contracts and interest rate swaps to hedge Canadian dollar and floating rate debt exposures. These risk management strategies pose certain risks, including the risk that losses on a hedge position may exceed the amount invested in such instruments. Moreover, a party in a hedging transaction may be unavailable or unwilling to settle our obligations, which could cause us to suffer corresponding losses. A hedging instrument may not be effective in eliminating all of the risks inherent in any particular position. Our profitability may be adversely affected during any period as a result of use of such instruments.

We may be adversely affected by currency fluctuations in the U.S. dollar versus the Canadian dollar and the Chinese renminbi.

We have significant operations in Canada which incur the majority of their metal supply costs in U.S. dollars but earn the majority of their sales in Canadian dollars. Additionally, we have significant assets in China. We may from time to time experience losses when the value of the U.S. dollar strengthens against the Canadian dollar or the Chinese renminbi, which could have a material adverse effect on our results of operations. In addition, we will be subject to translation risk when we consolidate our Canadian and Chinese subsidiaries net assets into our balance sheet. Fluctuations in the value of the U.S. dollar versus the Canadian dollar or Chinese renminbi could reduce the value of these assets as reported in our financial statements, which could, as a result, reduce our stockholders equity.

Risks Relating to Our Common Stock and this Offering

There is no existing market for our common stock, and we do not know if one will develop to provide you with adequate liquidity.

Prior to this offering, there has not been a public market for our common stock. We cannot predict the extent to which investor interest in our company will lead to the development of an active trading market on the New York Stock Exchange (NYSE), or otherwise, or how liquid that market might become. If an active trading market does not develop, you may have difficulty selling any of our common stock that you buy in this offering. Consequently, you may not be able to sell our common stock at prices equal to or greater than the price you paid in this offering. In addition, an inactive trading market may impair our ability to raise additional capital by selling shares and may impair our ability to acquire other companies by using our shares as consideration.

The initial public offering price of the shares has been determined by negotiations between the Company and the representative of the underwriters. Among the factors considered in determining the initial public offering price were our record of operations, our current financial condition, our future prospects, our markets, the economic conditions in and future prospects for the industry in which we compete, our management, and currently prevailing general conditions in the equity securities markets, including current market valuations of publicly traded companies considered comparable to our company. We cannot assure you, however, that the prices at which the shares will sell in the public market after this offering will not be lower than the initial public offering price or that an active trading market in our common stock will develop and continue after this offering.

Our stock price may be volatile, and your investment in our common stock could suffer a decline in value.

The stock markets have experienced extreme price and volume fluctuations that have affected and continue to affect the market prices of equity securities of many companies. These fluctuations have often been unrelated or disproportionate to the operating performance of those companies. These broad market and industry fluctuations, as well as general economic, political and market conditions such as recessions, interest rate changes or international currency fluctuations, may negatively affect the market price of our common stock. The initial public offering price for our common stock was determined by negotiations between the Company and the representative of the underwriters and may not be indicative of prices that will prevail in the open market following this offering. You may not be able to resell your shares at or above the initial public offering price due to fluctuations in the market price of our common stock caused by changes in our operating performance or prospects, including possible changes due to the cyclical nature of the metals distribution industry and other factors such as fluctuations in metals prices, which could cause short-term swings in profit margins. If the market price of our ordinary shares after this offering does not exceed the initial public offering price, you may not realize any return on your investment in us and may lose some or all of your investment. In addition, companies that have historically experienced volatility in the market price of their stock have been subject to securities class action litigation. We may be the target of this type of litigation in the future. Securities litigation against us could result in substantial costs and divert our management s attention from other business concerns.

Future sales of our common stock in the public market could lower our share price.

We may sell additional shares of common stock into the public markets after this offering. The market price of our common stock could decline as a result of sales of a large number of shares of our common stock in the public markets after this offering or the perception that these sales could occur. These sales, or the possibility that these sales may occur, also might make it more difficult for us to sell equity securities at a time and at a price that we deem appropriate.

After the consummation of this offering, we will have shares of common stock outstanding. Of the remaining outstanding shares, 5,000,000, or %, of our total outstanding shares will be restricted from immediate resale under the lock-up agreements between us and all of our directors, officers and stockholders and the underwriters described in the section entitled Underwriting below, but may be sold into the market after those lock-up restrictions expire, in certain limited circumstances as set forth in the lock-up agreements, or if they are waived by as the representative of the underwriters, in their discretion. The outstanding shares subject to the lock-up restrictions will generally become available for sale following the expiration of the lock-up agreements, which is 180 days after the date of this prospectus, subject to the volume limitations and manner-of-sale requirements under Rule 144 of the Securities Act of 1933, as amended (the Securities Act).

This offering will cause immediate and substantial dilution in net tangible book value.

The initial public offering price of a share of our common stock is substantially higher than the net tangible book value (deficit) per share of our outstanding common stock immediately after this offering. Net tangible book value (deficit) per share represents the amount of total tangible assets less total liabilities, divided by the number of shares of common stock outstanding. If you purchase our common stock in this offering, you will incur an immediate dilution of approximately $ in the net tangible book value per share of common stock based on our net tangible book value as of September 30, 2013. You may experience additional dilution if we issue common stock in the future. As a result of this dilution, you may receive significantly less than the full purchase price you paid for the shares in the event of a liquidation. See Dilution.

Our controlling stockholder and its affiliates will be able to influence matters requiring stockholder approval and could discourage the purchase of our outstanding shares at a premium.

Prior to this offering, Platinum owned 99% of our outstanding common stock. Upon completion of this offering, Platinum will continue to control all matters submitted for approval by our stockholders through its ownership of approximately % of our outstanding common stock. These matters could include the election of all of the members of our Board of Directors, amendments to our organizational documents, or the approval of any proxy contests, mergers, tender offers, sales of assets or other major corporate transactions.

Upon the consummation of this offering, the Company and Platinum will enter into an amended and restated investor rights agreement (the Investor Rights Agreement) which will provide, among other things, that for so

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long as Platinum collectively beneficially owns (i) at least 30% of the voting power of the outstanding capital stock of the Company, Platinum will have the right to nominate for election to the board of directors of the Company no fewer than that number of directors that would constitute a majority of the number of directors if there were no vacancies on the board, (ii) at least 15% but less than 30% of the voting power of the outstanding capital stock of the Company, Platinum will have the right to nominate two directors and (iii) at least 5% but less than 15% of the voting power of the outstanding capital stock of the Company, Platinum will have the right to nominate one director. The agreement will also provide that if the size of the board of directors is increased or decreased at any time, Platinum s nomination rights will be proportionately increased or decreased, respectively, rounded up to the nearest whole number, except that if the board of directors increases its size within 180 days of the date of the agreement, Platinum will have the right to designate director nominees to fill each newly created directorship. As a result of Platinum s ownership of a majority of the Company s outstanding capital stock as well its board nomination rights pursuant to the Investor Rights Agreement as described above, Platinum will continue to be able to significantly influence or effectively control our policies and operations, including the appointment of management, future issuances of our common stock or other securities and the payment of dividends. In addition, Platinum will have significant control over our decisions to enter into any other corporate transaction. For additional information on the Investor Rights Agreement and Platinum s rights thereunder, please see Certain Relationships and Related Party Transactions Investor Rights Agreement.

The interests of Platinum may not in all cases be aligned with your interests as a holder of common stock. For example, a sale of a substantial number of shares of stock in the future by Platinum could cause our stock price to decline. Further, Platinum could cause us to make acquisitions that increase the amount of the indebtedness that is secured or senior to the Company s existing debt or sell revenue-generating assets, impairing our ability to make payments under such debt. Additionally, Platinum is in the business of making investments in companies and may from time to time acquire and hold interests in businesses that compete directly or indirectly with us. Accordingly, Platinum may also pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us. In addition, Platinum may have an interest in pursuing acquisitions, divestitures and other transactions that, in their judgment, could enhance their equity investment, even though such transactions might involve risks to you as a holder of our common stock. For example, in January 2010, we closed an offering (the Ryerson Holding Offering) pursuant to which we issued the Ryerson Holding Notes, 96% of the gross proceeds of which were paid to Platinum as a cash dividend.

We are exempt from certain corporate governance requirements because we are a controlled company within the meaning of the NYSE rules and, as a result, you will not have the protections afforded by these corporate governance requirements.

Because Platinum will control more than 50% of the voting power of our common stock after this offering, we are considered to be a controlled company for purposes of the NYSE listing requirements. Under the NYSE rules, a controlled company may elect not to comply with certain NYSE corporate governance requirements, including (1) the requirement that a majority of our Board of Directors consist of independent directors, (2) the requirement that the nominating and corporate governance committee of our Board of Directors be composed entirely of independent directors, (3) the requirement that the compensation committee of our Board of Directors be composed entirely of independent directors and (4) the requirement for an annual performance evaluation of the nomination/corporate governance and compensation committees. Given that Platinum will control a majority of the voting power of our common stock after this offering, we are permitted, and have elected, to opt out of compliance with certain NYSE corporate governance requirements. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

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We will incur increased costs and demands upon our management and other personnel as a result of complying with the laws and regulations affecting public companies, which could harm our operating results.

As a public company, we will incur significant legal, accounting and other expenses. In addition, the Sarbanes-Oxley Act, as well as related rules implemented by the SEC and the NYSE, impose various requirements on public companies. Our management and other personnel will need to devote a substantial amount of time to these compliance requirements. Although prior to October 2012 we were filing Forms 10-K and 10-Q pursuant to the terms of our then outstanding notes, these rules will increase our legal and financial compliance costs and will make certain activities more time-consuming and costly. To the extent we become an accelerated or large accelerated filer, our annual reports must also contain a statement that our independent registered public accounting firm has issued an attestation report on the effectiveness of our internal control over financial reporting.

The Sarbanes-Oxley Act requires, among other things, that we maintain effective internal control over financial reporting and disclosure controls and procedures. In particular, we will be required to perform system and process evaluation and testing of our internal control over financial reporting to allow management and our independent registered accounting firm to report on the effectiveness of our internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act. Our compliance with Section 404 will require that we incur substantial accounting expense and expend significant management time on compliance-related issues. If our management identifies one or more material weaknesses in our internal control over financial reporting, we will be unable to assert that our internal control over financial reporting is effective. If we are unable to assert that our internal control over financial reporting is effective, or if our independent registered public accounting firm is unable to express an opinion on the effectiveness of our internal control over financial reporting, market perception of our financial condition and the trading price of our stock may be adversely affected and customer perception of our business may suffer.

Our corporate documents and Delaware law will contain provisions that could discourage, delay or prevent a change in control of the Company.

Our amended and restated certificate of incorporation and amended and restated bylaws will contain provisions that may make the acquisition of our company more difficult without the approval of our Board of Directors. These provisions:

- establish a classified Board of Directors so that not all members of our Board of Directors are elected at one time;
- authorize the issuance of undesignated preferred stock, the terms of which may be established and the shares of which may be issued without stockholder approval, and which may include super voting, special approval, dividend, or other rights or preferences superior to the rights of the holders of common stock;
- provide that the Board of Directors is expressly authorized to make, alter, or repeal our amended and restated bylaws;
- prohibit stockholders from acting by written consent if less than a majority of the voting power of our outstanding stock is controlled by Platinum; and
- establish advance notice requirements for nominations for elections to our Board of Directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

These anti-takeover provisions and other provisions under Delaware law could discourage, delay or prevent a transaction involving a change in control of our company, even if doing so would benefit our stockholders. These provisions could also discourage proxy contests and make it more difficult for you and other stockholders to elect directors of your choosing and to cause us to take other corporate actions you desire.

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Any issuance of preferred stock could make it difficult for another company to acquire us or could otherwise adversely affect holders of our common stock, which could depress the price of our common stock.

Upon completion of this offering, our Board of Directors will have the authority to issue preferred stock and to determine the preferences, limitations and relative rights of shares of preferred stock and to fix the number of shares constituting any series and the designation of such series, without any further vote or action by our stockholders. Our preferred stock could be issued with voting, liquidation, dividend and other rights superior to the rights of our common stock. The potential issuance of preferred stock may delay or prevent a change in control of us, discouraging bids for our common stock at a premium over the market price, and adversely affect the market price and the voting and other rights of the holders of our common stock.

We do not intend to pay regular cash dividends on our stock after this offering.

We do not anticipate declaring or paying regular cash dividends on our common stock or any other equity security in the foreseeable future. The amounts that may be available to us to pay cash dividends are restricted under our debt agreements. Any payment of cash dividends on our common stock in the future will be at the discretion of our Board of Directors and will depend upon our results of operations, earnings, capital requirements, financial condition, future prospects, contractual restrictions and other factors deemed relevant by our Board of Directors. Therefore, you should not rely on dividend income from shares of our common stock. For more information, see Dividend Policy. Your only opportunity to achieve a return on your investment in us may be if the market price of our common stock appreciates and you sell your shares at a profit but there is no guarantee that the market price for our common stock after this offering will ever exceed the price that you pay for our common stock in this offering.

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FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements. Such statements can be identified by the use of forward-looking terminology such as believes, expects, may, estimates, will, should, plans or anticipates or the negative thereof or other variations thereon or comparable terminology, or by discussions of strategy. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and may involve significant risks and uncertainties, and that actual results may vary materially from those in the forward-looking statements as a result of various factors. Among the factors that significantly impact the metals distribution industry and our business are:

- cyclicality of our business, due to the cyclical nature of our customers businesses;
- impairment of goodwill that could result from, among other things, volatility in the markets in which we operate;
- remaining competitive and maintaining market share in the highly fragmented metals distribution industry, in which price is a competitive tool and in which customers who purchase commodity products are often able to source metals from a variety of sources;
- managing the costs of purchased metals relative to the price at which we sell our products during periods of rapid price escalation, when we may not be able to pass through pricing increases fully to our customers quickly enough to maintain desirable gross margins, or during periods of generally declining prices, when our customers may demand that price decreases be passed fully on to them more quickly than we are able to obtain similar discounts from our suppliers;
- our substantial indebtedness and the covenants in instruments governing such indebtedness;
- the failure to effectively integrate newly acquired operations;
- regulatory and other operational risks associated with our operations located outside of the United States;
- fluctuating operating results depending on seasonality;
- potential damage to our information technology infrastructure;
- work stoppages;
- certain employee retirement benefit plans that are underfunded and the actual costs could exceed current estimates;
- future funding for postretirement employee benefits may require substantial payments from current cash flow;
- prolonged disruption of our processing centers;

ability to retain and attract management and key personnel;

ability of management to focus on North American and foreign operations;

termination of supplier arrangements;

the incurrence of substantial costs or liabilities to comply with, or as a result of violations of, environmental laws;

the impact of new or pending litigation against us;

a risk of product liability claims;

following this offering, a single investor group will continue to control all matters submitted for approval by our stockholders, and the interests of that single investor group may conflict with yours as a holder of our common stock;

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- our risk management strategies may result in losses;
- currency fluctuations in the U.S. dollar versus the Canadian dollar and the Chinese renminbi;
- management of inventory and other costs and expenses; and
- consolidation in the metals producer industry, from which we purchase products, which could limit our ability to effectively negotiate and manage costs of inventory or cause material shortages, either of which would impact profitability.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should, therefore, be considered in light of various factors, including those set forth in this prospectus under Risk Factors and the caption Industry and Operating Trends included in Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this prospectus. Moreover, we caution you not to place undue reliance on these forward-looking statements, which speak only as of the date they were made. We do not undertake any obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances after the date of this prospectus or to reflect the occurrence of unanticipated events.

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USE OF PROCEEDS

We estimate that the net proceeds from the sale of the shares of common stock that we are offering will be approximately $ million after deducting the underwriting discount and estimated offering expenses of $ million and assuming an initial public offering price of $ per share, the mid-point of the estimated initial public offering price range. A $1.00 increase (decrease) in the assumed initial public offering price of $ per share would increase (decrease) the net proceeds from the sales of shares of common stock that we are offering by $ million after deducting the underwriting discount and estimated offering expenses of $ million.

We intend to use the net proceeds to us from this offering to (i) redeem $ in aggregate principal amount of the 11.25% Senior Notes due 2018 issued by Ryerson and its wholly owned subsidiary Joseph T. Ryerson & Son Inc. (the 2018 Notes), (ii) repay approximately $ of the borrowings outstanding under our $1.35 billion revolving credit facility agreement that matures on the earlier of (a) April 3, 2018 or (b) August 16, 2017 (60 days prior to the scheduled maturity date of the 2017 Notes), if the 2017 Notes are then outstanding (as amended, the Ryerson Credit Facility), (iii) pay Platinum Advisors $ as consideration for terminating the Services Agreement, (iv) redeem up to $ in aggregate principal amount of the 9% Senior Secured Notes due 2017 issued by Ryerson and its wholly owned subsidiary Joseph T. Ryerson & Son Inc. (the 2017 Notes and together with the 2018 Notes, the 2017 and 2018 Notes) and (v) pay related transaction fees, expenses and premiums in connection with this offering, which we currently expect to equal approximately $22.0 million. The proceeds from the offering of the 2017 and 2018 Notes were used by us to (a) repay in full our 14 ½% Senior Discount Notes due 2015 (the Ryerson Holding Notes), plus accrued and unpaid interest up to, but not including, the repayment date of the Ryerson Holding Notes, (b) repay in full our Floating Rate Senior Secured Notes due November 1, 2014 (the 2014 Notes), plus accrued and unpaid interest up to, but not including, the repayment date of the 2014 Notes, (c) repay in full our 12% Senior Secured Notes due November 1, 2015 (the 2015 Notes and together with the 2014 Notes, the Old Ryerson Notes), plus accrued and unpaid interest up to, but not including, the repayment date of the 2015 Notes, (d) repay outstanding indebtedness under the Ryerson Credit Facility and (e) pay related transaction fees, expenses and premiums in connection with the offering of the 2017 and 2018 Notes.

We will not receive any proceeds resulting from any exercise by the underwriters of the over-allotment option to purchase additional shares from the selling stockholders identified in this prospectus. In the aggregate, if the over-allotment is exercised, the selling stockholders will receive approximately $ million after deducting the underwriting discount and estimated offering expenses of $ million and assuming an initial public offering price of $ per share, the mid-point of the estimated initial public offering price range.

The foregoing represents our current intentions with respect to the use and allocation of the net proceeds of this offering based upon our present plans and business conditions, but our management will have significant flexibility and discretion in applying the net proceeds. The occurrence of unforeseen events or changed business conditions could result in application of the net proceeds of this offering in a manner other than as described in this prospectus.

Pending our use of any of the net proceeds of this offering for the purposes stated above, we may invest such proceeds in investment grade, short-term, interest-bearing securities or other investments approved by our management.

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and our total capitalization as of September 30, 2013:

- on a historical basis; and

- on an As adjusted basis to give effect to (1) the sale of shares of our common stock offered hereby assuming an initial public offering price of $ per share, the mid-point of the estimated initial public offering price range, (2) the application of the net proceeds from this offering as described in Use of Proceeds and (3) the Services Agreement Termination.

You should read this table together with the information contained in Use of Proceeds, Selected Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related financial information contained elsewhere in this prospectus.

	As of September 30, 2013	
	Historical	As adjusted(1)
	($ in millions)	
Cash and cash equivalents	$ 81.1	$ 81.1
Debt:		
Ryerson Credit Facility(2)(3)	318.5	
Ryerson Inc. 9% Senior Secured Notes due 2017	600.0	
Ryerson Inc. 11 $^{1}/_{4}$% Senior Notes due 2018	300.0	
Foreign debt	21.6	21.6
Total debt	1,240.1	
Redeemable noncontrolling interest	1.3	1.3
Equity:		
Common Stock, par value $0.01 per share, 10,000,000 shares authorized, and 5,000,000 issued and outstanding; 10,000,000 shares authorized, and issued and outstanding, as adjusted(4)		
Paid-in-capital	189.9	
Accumulated deficit(5)	(225.3)	
Accumulated other comprehensive loss	(253.5)	(253.5)
Noncontrolling interest	2.0	2.0
Total stockholders equity (deficit)	(286.9)	
Total capitalization	$ 954.5	$

(1) A $1.00 increase (decrease) in the assumed initial public offering price of $ per share would increase (decrease) total stockholders equity by $ million assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting the underwriting discount and estimated offering expenses of $ million.

(2) In connection with this offering, Platinum and JT Ryerson intend to terminate the Services Agreement, pursuant to which JT Ryerson will pay Platinum Advisors $ million as consideration for terminating the monitoring fee payable thereunder. The As Adjusted amount reflects the expense incurred for the payment of the termination fee. For a discussion of the Services Agreement, see Certain Relationships and Related Party Transactions.

(3) As of October 31, 2013, we had approximately $364 million outstanding and $243 million of availability under the Ryerson Credit Facility.

(4) Share amounts give effect to the for 1.00 stock split that will occur prior to the closing of this offering.

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The number of shares of our common stock shown as issued and outstanding in the table above excludes (i) shares of our common stock that may be purchased by the underwriters to cover over-allotments and (ii) shares of common stock reserved for future grants under our stock incentive plan (assuming our stock incentive plan, which is described in Executive Compensation Stock Incentive Plan, is adopted in connection with this offering).

(5) The As Adjusted amount reflects the $ million fee paid to Platinum Advisors in consideration for terminating the Services Agreement.

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of our common stock to be sold in this offering will exceed the net tangible book value per share of our common stock immediately after this offering. The net tangible book value per share presented below is equal to the amount of our total tangible assets (total assets less intangible assets) less total liabilities as of September 30, 2013, divided by the number of shares of our common stock that would have been held by our common stockholders of record immediately prior to this offering after giving effect to the for 1.00 stock split. Our net tangible book value as of September 30, 2013, was approximately $ million, or $ per share. After giving effect to the sale of the shares of common stock we propose to offer pursuant to this prospectus at an assumed public offering price of $ per share, the mid-point of the range of estimated initial public offering prices set forth on the cover page of this prospectus and the application of the net proceeds therefrom, and after deducting the underwriting discount and estimated offering expenses, our net tangible book value as of September 30, 2013 would have been $ million, or $ per share. This represents an immediate dilution in net tangible book value of $ per share.

The following tables illustrate this dilution:

Initial public offering price per share		$
Net tangible book value per share at September 30, 2013	$	
Increase in net tangible book value per share attributable to cash payments made by new investors		
Net tangible book value per share after this offering		
Dilution of net tangible book value per share to new investors		$

A $1.00 increase (decrease) in the assumed initial public offering price of $ per share (the mid-point of the range on the cover page of this prospectus) would (decrease) increase our net tangible book value (deficit) by $ million, the net tangible book value (deficit) per share after this offering by $ per share and the decrease in net tangible book value (deficit) to new investors in this offering by $ per share, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting the estimated underwriting discounts and commissions and estimated offering expenses.

The following table summarizes the number of shares purchased from us and the total consideration and average price per share paid to us, by existing holders of common stock, and the total number of shares purchased from the Company, the total consideration paid to the Company and the price per share paid by new investors purchasing shares in this offering:

	Shares Purchased		Total Consideration		Average Price Per Share
	Number	Percent	Amount	Percent	Share
	(dollars in thousands, except per share amounts)				
Existing holders of common stock		%	$	%	$
Investors purchasing common stock in this offering					
Total		100%	$	100%	$

If the underwriters over-allotment option is exercised in full:

- the percentage of our shares of common stock held by our existing holders of common stock will decrease to shares, or approximately % of the total number of shares of common stock outstanding after this offering; and the number of our shares of common stock held by investors purchasing common stock in this offering will increase to shares, or approximately % of the total number of shares of common stock outstanding after this offering.

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DIVIDEND POLICY

We have in the past paid cash dividends to our stockholders. See Certain Relationships and Related Party Transactions Dividend Payments. We do not currently anticipate declaring or paying regular cash dividends on our common stock in the foreseeable future. Any payment of cash dividends on our common stock in the future will be at the discretion of our Board of Directors and will depend upon our results of operations, earnings, capital requirements, financial condition, future prospects, contractual restrictions, including restrictions contained in our existing debt documents or the terms of any of our future debt or other agreements that we may enter into from time to time, and other factors deemed relevant by our Board of Directors. See Description of Certain Indebtedness, and Description of Capital Stock Common Stock.

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SELECTED CONSOLIDATED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial information. Our selected historical consolidated statements of operations data for the years ended December 31, 2010, 2011 and 2012 and the summary historical balance sheet data as of December 31, 2011 and 2012 have been derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected historical consolidated statements of operations data for the years ended December 31, 2008 and 2009 and the summary historical balance sheet data as of December 31, 2008, 2009 and 2010 were derived from the audited financial statements and related notes thereto, which are not included in this prospectus.

Our selected historical consolidated financial data as of September 30, 2012 and 2013 and for the nine months ended September 30, 2012 and 2013 have been derived from our unaudited consolidated financial statements included elsewhere in this prospectus. The September 30, 2012 and 2013 unaudited financial statements have been prepared on a basis consistent with our audited consolidated financial statements and reflect all adjustments, consisting of normal recurring adjustments that are, in the opinion of management, necessary for a fair presentation of the financial position and results of operations for the periods presented. The results of any interim period are not necessarily indicative of the results that may be expected for any other interim period or for the full fiscal year, and the historical results set forth below do not necessarily indicate results expected for any future period.

The information presented below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and the notes thereto included elsewhere in this prospectus. The share and per share information presented below has been adjusted to give effect to the for 1.00 stock split that will occur prior to the closing of this offering.

	Year Ended December 31,					Nine Months Ended September 30,	
	2008	2009	2010	2011	2012	2012	2013
Statements of Operations Data:	($ in millions, except per share data)						
Net sales	$ 5,309.8	$ 3,066.1	$ 3,895.5	$ 4,729.8	$ 4,024.7	$ 3,174.4	$ 2,657.8
Cost of materials sold	4,596.9	2,610.0	3,355.7	4,071.0	3,315.1	2,619.1	2,188.4
Gross profit(1)	712.9	456.1	539.8	658.8	709.6	555.3	469.4
Warehousing, selling, general and administrative	586.1	483.8	506.9	539.7	508.9	389.9	363.2
Restructuring and other charges			12.0	11.1	1.1		2.1
Gain on insurance settlement			(2.6)				
Gain on sale of assets		(3.3)					
Impairment charges on fixed assets and goodwill		19.3	1.4	9.3	1.0	0.9	8.8
Pension and other postretirement benefits curtailment (gain) loss		(2.0)	2.0		(1.7)		
Operating profit (loss)	126.8	(41.7)	20.1	98.7	200.3	164.5	95.3
Other income and (expense), net(2)	29.2	(10.1)	(3.2)	4.6	(33.5)	(1.0)	2.1
Interest and other expense on debt(3)	(109.9)	(72.9)	(107.5)	(123.1)	(126.5)	(97.6)	(83.3)
Income (loss) before income taxes	46.1	(124.7)	(90.6)	(19.8)	40.3	65.9	14.1
Provision (benefit) for income taxes(4)	14.8	67.5	13.1	(11.0)	(5.5)	9.6	5.9
Net income (loss)	31.3	(192.2)	(103.7)	(8.8)	45.8	56.3	8.2
Less: Net income (loss) attributable to noncontrolling interest	(1.2)	(1.5)	0.3	(0.7)	(1.3)	(0.7)	(0.9)
Net income (loss) attributable to Ryerson Holding Corporation	$ 32.5	$ (190.7)	$ (104.0)	$ (8.1)	$ 47.1	$ 57.0	$ 9.1

Earnings (loss) per share of common stock:							
Basic:							
Basic earnings (loss) per share	$ 6.50	$ (38.14	134	197	— %	—%	8%
Gulf of Mexico shelf and other	280	340	551	— %	4 %	4 %	
Total offshore	582	938	1,389	— %	32 %	39 %	
Total	1,413	1,575	1,843	100 %	100%	100%	

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2013.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	1,091	158	233	167	1,324	325
Texas (a)	13,038	11,144	22,889	20,685	35,927	31,829
Federal onshore (b)	—	—	64,963	64,963	64,963	64,963
Total	14,129	11,302	88,085	85,815	102,214	97,117

(a) A portion of our Texas acreage requires continued drilling to hold the acreage for which we have included in our development plans, though the cost to renew this acreage, if necessary, is not considered material.

(b) The Company’s lease of this acreage, located in Nevada, has approximately four years remaining, and had a carrying value at December 31, 2013 of approximately $2.6 million included in the Company’s unevaluated properties balance. The lease requires no drilling activity to hold the acreage, and we continue to evaluate our position and monitor the activity of other operators conducting drilling in the area.

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Undeveloped Acreage Expirations

The following table sets forth by geographic area as of December 31, 2013 the number of our leased gross and net undeveloped acres that will expire over the next three years unless production begins before lease expiration dates. Gross amounts may be more than net amounts in a particular year due to timing of expirations.

	Net				Gross
	2014	2015	2016	Total	
Texas:					
Southern Permian Basin	165	—	—	165	165
Central Permian Basin	—	—	—	—	—
Northern Permian Basin (a)	10,586	7,282	327	18,195	19,755
Nevada: (b)	—	—	—	—	—
Total acreage	10,751	7,282	327	18,360	19,920

(a) 2,133 net acres have expired as of March 7, 2014. 16,062 of the total remaining net acres include extension options that would allow us to extend the primary term for a period of two years.
(b) The Company's lease of this acreage does not expire until 2018.

The expiring acreage set forth in the table above accounts for 21% of our net undeveloped acreage (85,815 total net acres). We are continually engaged in a combination of drilling and development and discussions with mineral lessors for lease extensions, renewals, new drilling and development units and new leases to address the expiration of undeveloped acreage that occurs in the normal course of our business.

Title to Properties

The Company believes that the title to its oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. The Company's properties are typically subject, in one degree or another, to one or more of the following:

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

To the extent that such burdens and obligations affect the Company's rights to production revenues, these characteristics have been taken into account in calculating Callon's net revenue interests and in estimating the size and value of its reserves. The Company believes that the burdens and obligations affecting our properties are typical within the industry for properties of the kind owned by Callon.

Insurance

In accordance with industry practice, the Company maintains insurance against some, but not all, of the operating risks to which its business is exposed. While not all inclusive, the Company's insurance policies include coverage for general liability insuring onshore operations (including sudden and accidental pollution), aviation liability, auto liability, worker's compensation, and employer's liability. The company carries control of well insurance for only those onshore operations that it is contractually bound to do so. At the depths and in the areas in which the Company operates, and in light of the vertical and horizontal drilling that it undertakes, the Company typically does not encounter high pressures or extreme drilling conditions onshore.

Currently, the Company has general liability insurance coverage up to $1 million per occurrence and $2 million per policy in the aggregate, which includes sudden and accidental environmental liability coverage for the effects of pollution on third parties arising from its operations. The Company's insurance policies contain high policy limits, and in most cases, deductibles (generally ranging from $0 to $250,000) that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. In addition, the Company maintains up to $100 million in excess liability coverage, which is in addition to and triggered if the underlying liability limits have been reached.

The Company requires all of its third-party contractors to sign master service agreements in which they agree to indemnify the Company for injuries and deaths of the service provider's employees, as well as contractors and subcontractors hired by the service provider. Similarly, the Company generally agrees to indemnify each third-party contractor against claims made by employees of the Company and the Company's other contractors. Additionally, each party generally is responsible for damage to its own property.

The third-party contractors that perform hydraulic fracturing operations for the Company sign master service agreements generally containing the indemnification provisions noted above. The Company does not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. However, the Company believes its general liability and excess liability insurance policies would cover foreseeable third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies.

The Company re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. While based on the Company's risk analysis, it believes that it is properly insured, no assurance can be given that the Company will be able to maintain insurance in the future at rates that it considers reasonable. In such circumstances, the Company may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Major Customers

Our production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and natural gas production, on an equivalent basis, during each of the 12-month periods ended:

	December 31,					
	2013		2012		2011	
Enterprise Crude Oil, LLC	38	%	32	%	16	%
Shell Trading Company	31	%	39	%	45	%
Plains Marketing, L.P.	15	%	15	%	17	%
Other	16	%	14	%	22	%
Total	100	%	100	%	100	%

Because alternative purchasers of oil and natural gas are readily available, the Company believes that the loss of any of these purchasers would not result in a material adverse effect on Callon's ability to market future oil and natural gas production. We are not currently committed to provide a fixed and determinable quantity of oil or gas in the near future under our contracts.

Corporate Offices

The Company's headquarters are located in Natchez, Mississippi, in approximately 51,500 square feet of owned space. We also maintain leased business offices in Houston and Midland, Texas. Because alternative locations to our leased spaces are readily available, the replacement of any of our leased offices would not result in material expenditures.

Employees

Callon had 94 employees as of December 31, 2013. None of the Company's employees are currently represented by a union, and the Company believes that it has good relations with its employees.

Regulations

General. Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the entire oil and natural gas industry is continuously being reviewed for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply.

Exploration and Production. Our operations are subject to federal, state and local regulations that include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds and letters of credit) covering drilling and well operations. Other activities subject to regulation are:

- the location and spacing of wells,
- the method of drilling and completing and operating wells,
- the rate and method of production,
- the surface use and restoration of properties upon which wells are drilled and other exploration activities,
- notice to surface owners and other third parties,
- the plugging and abandoning of wells,
- the discharge of contaminants into water and the emission of contaminants into air,
- the disposal of fluids used or other wastes obtained in connection with operations,
- the marketing, transportation and reporting of production, and
- the valuation and payment of royalties.

Operations conducted on federal or state oil and natural gas leases must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Department of the Interior (“DOI”) Bureaus or other appropriate federal or state agencies.

Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity.

Various proposals and proceedings that might affect the petroleum industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, various state legislatures, and the courts. The industry historically has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

We do not currently anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Matters and Regulation. Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency, or the EPA, issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. Violations of environmental laws could result in administrative, civil or criminal fines and injunctive relief. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements.

Waste Handling. The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute “solid wastes” that are subject to the less stringent requirements of non-hazardous waste provisions may not be exempt under state programs. However, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the “Clean Water Act,” the Safe Drinking Water Act, the Oil Pollution Act, or OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters for analogous state programs. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges produced by natural gas extraction from underground coalbed and shale formations. The EPA stated that it will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for coalbed methane and shale gas in 2014. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail below in "-Regulation of Hydraulic Fracturing." These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties and seek injunctive relief for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Greenhouse Gas (GHG) Regulation. Although federal legislation regarding the control of greenhouse gasses, or GHGs, thus far has been unsuccessful, the EPA has moved forward with rulemaking to regulate GHGs as pollutants under the CAA. These GHG regulations may require us to incur increased operating costs and may have an adverse effect on demand for the oil and natural gas we produce.

The EPA, as of January 2, 2011, requires the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs in a multi-step process, with the largest sources first subject to permitting. Those permitting provisions, should they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those requirements. EPA has adopted a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions if the total emissions within a basin exceed 25,000 metric tons CO_2 equivalent per year. Although this rule does not limit the amount of GHGs that can be emitted, it requires us to incur costs to monitor, keep records of, and potentially report GHG emissions associated with our operations if the reporting threshold is reached with production growth.

In addition to federal regulation, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These potential regional and state initiatives may result in so-called "Cap-and-Trade programs", under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in our incurring material expenses to comply, such as by being required to purchase or to surrender allowances for GHGs resulting from our operations. The federal, regional and local regulatory initiatives also could adversely affect the marketability of the oil and natural gas we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

Regulation of Hydraulic Fracturing. Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of Congress but have not passed.

The EPA, however, issued guidance on permitting hydraulic fracturing that uses fluids containing diesel fuel under the UIC program, specifically as "Class II" UIC wells. At the same time, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and the EPA has commenced a study of the potential impacts of hydraulic fracturing activities on drinking water resources. The EPA has announced that it plans to propose standards in 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

On August 16, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA may issue revised rules that are likely responsive to some of these requests. For example, on April 12, 2013, the EPA published a proposed amendment extending compliance dates for certain storage vessels. The final revised rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would update existing regulation for hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. EPA has announced that it is considering regulations under the Toxic Substance Control Act to require evaluation and disclsoure of hydraulic fracturing.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts, the results of which are expected in 2014. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities.

Several states, including Texas, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission has adopted rules and regulations implementing this legislation that apply to all wells for which the Railroad Commission issues an initial drilling permit after February 1, 2012. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Surface Damage Statutes ("SDAs"). In addition, a number of states and some tribal nations have enacted SDAs. These laws are designed to compensate for damage caused by oil and gas development operations. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain binding requirements for payments to the operator in connection with exploration and operating activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

National Environmental Policy Act and Endangered Species Act. Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having 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. To the extent that 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 or impose additional conditions upon the development of oil and natural gas projects.

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company were to have a portion of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

Mineral Leasing Act of 1920 ("Mineral Act"). The Mineral Act prohibits direct or indirect ownership of any interest in federal onshore oil and natural gas leases by a foreign citizen or a foreign corporation except through stock ownership in a corporation formed under the laws of the United States or of any U.S. state or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or corporations of the United States. If these restrictions are violated, the oil and gas lease or leases can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the Bureau of Land Management ("BLM") (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. The Company owns an interest in federal leaseholds in Nevada. It is possible that holders of the Company's equity interests may be citizens of foreign countries, which could be determined to be citizens of a non-reciprocal country under the Mineral Act. In such event, the federal onshore oil and gas leases held by the Company could be subject to cancellation based on such determination.

Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. 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 requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. 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. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill. Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

Oil and NGLs Sales and Transportation. Sales of oil and condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Commitments and Contingencies

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies included, and claims for damages to property, employees, other persons, and the environment resulting from the Company's operations could have on its activities. See Note 13 for additional information.

Available Information

We make available free of charge on our Internet web site (www.callon.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the SEC. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, like Callon, that file electronically with the SEC.

We also make available within the Investors section of our Internet web site our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation and Nominating and Governance Committee Charters, which have been approved by our board of directors. We will make timely disclosure by a Current Report on Form 8-K and on our web site of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers. A copy of our Code of Business Conduct and Ethics is also available, free of charge by writing us at: Chief Financial Officer, Callon Petroleum Company, P.O. Box 1287, Natchez, MS 39121.

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Item 1A. Risk Factors
Risk Factors
Depressed oil and natural gas prices may adversely affect our results of operations and financial condition. Our success is highly dependent on prices for oil and natural gas, which are extremely volatile, and the oil and natural gas markets are cyclical. Extended periods of low prices for oil or natural gas will have a material adverse effect on us. The prices of oil and natural gas depend on factors we cannot control such as weather, economic conditions, and levels of production, actions by OPEC and other countries and government actions. Prices of oil and natural gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and natural gas that we are economically able to produce;
- our ability to attract capital to finance our operations and the cost of the capital;
- the amount we are allowed to borrow under our credit facilities;
- the profit or loss we incur in exploring for and developing our reserves; and
- the value of our oil and natural gas properties.

Any substantial and extended decline in the price of oil or natural gas could have an adverse effect on our borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows.

If oil and natural gas prices decrease and remain depressed for extended periods of time, we may be required to take additional writedowns of the carrying value of our oil and natural gas properties. We may be required to writedown the carrying value of our oil and natural gas properties when oil and natural gas prices are low. Under the full-cost method, which we use to account for our oil and natural gas properties, the net capitalized costs of our oil and natural gas properties may not exceed the present value, discounted at 10%, of future net cash flows from estimated net proved reserves, using the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month, plus the lower of cost or fair market value of our unproved properties. If net capitalized costs of our oil and natural gas properties exceed this limit, we must charge the amount of the excess to earnings. This type of charge will not affect our cash flows, but will reduce the book value of our stockholders' equity. We review the carrying value of our properties quarterly and once incurred, a writedown of oil and natural gas properties is not reversible at a later date, even if prices increase. See Note 12 to our Consolidated Financial Statements.

Our actual recovery of reserves may substantially differ from our proved reserve estimates and our proved reserve estimates may change over time. This Form 10-K contains estimates of our proved oil and natural gas reserves and the estimated future net cash flows from such 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 and is therefore inherently imprecise. In addition, drilling, testing and production data acquired since the date of an estimate may justify revising an estimate.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from the estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based on production history, development drilling and exploration activities and prices of oil and natural gas. We incorporate many factors and assumptions into our estimates including:

- Expected reservoir characteristics based on geological, geophysical and engineering assessments;
- Future production rates;
- Future oil and natural gas prices and quality and locational differences; and

• Future development and operating costs.

You should not assume that any present value of future net cash flows from our estimated net proved reserves contained in this Form 10-K represents the market value of our oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2013 on average 12-month prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations or taxes. At December 31, 2013, approximately 33% of the discounted present value of our estimated net proved reserves consisted of PUDs. PUDs represented 50% of total proved reserves by volume. Recovery of PUDs generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

Information about reserves constitutes forward-looking information. See “Forward-Looking Statements” for information regarding forward-looking information.

Unless we replace our oil and gas reserves, our reserves and production will decline. Our future oil and gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our production, revenues, reserve quantities and cash flows will decline. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

Exploring for, developing, or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments to develop our reserves, if our cash flows from operations decline or external sources of capital become limited or unavailable. As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures, currently expected to be in excess of three times the cost, as compared to the drilling of a traditional vertical well. If we do not replace the reserves we produce, our reserves revenues and cash flow will decrease over time, which will have an adverse effect on our business.

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all. Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings under our credit facility and public debt and equity financings. In 2013, our total capital expenditures, including expenditures for leasehold interests and property acquisitions, drilling, seismic and infrastructure, were approximately $171 million. Our 2014 capital budget for drilling, completion and infrastructure is estimated to be approximately $185 million. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

If the borrowing base under our revolving credit facility or our revenues decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our leases and a decline in our estimated net proved reserves, and could adversely affect our business, financial condition and results of operations.

Our revolving credit facility and second lien term loan facility contain restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities. Our credit facilities restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- create additional liens;
- sell assets;
- merge or consolidate with another entity;
- pay dividends or make other distributions;
- engage in transactions with affiliates; and
- enter into certain swap agreements.

In addition, we will be required to use substantial portions of our future cash flow to repay principal and interest on our indebtedness. Our credit facilities require us to maintain certain financial ratios and tests, including a minimum asset value coverage ratio of total debt. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

Our borrowings under our revolving credit facility and second lien term loan facility expose us to interest rate risk. Our earnings are exposed to interest rate risk associated with borrowings under our revolving credit facility, which bear interest at a rate elected by us that is based on the prime, LIBOR or federal funds rate plus margins ranging from 0.75% to 2.75% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. Our second lien term loan facility bears interest at a rate of LIBOR plus 7.75%. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

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. From time to time, our industry has experiences 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.

Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner. Water is an essential component of our drilling and hydraulic fracturing processes. Historically, we have been able to secure water from local landowners and other sources for use in our operations. During the last few years, West Texas has experienced extreme drought conditions. As a result of the severe drought, some local water districts may begin restricting the use of water under their jurisdiction for drilling and hydraulic fracturing to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, NGLs and natural gas, which could have an adverse effect on our business, financial condition and results of operations.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area. All of our producing properties are geographically concentrated in the Permian Basin of West Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of oil, natural gas or natural gas liquids. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.
Our exploration projects increase the risks inherent in our oil and natural gas activities. We may seek to replace reserves through exploration, where the risks are greater than in acquisitions and development drilling. During 2012, we purchased 21,419 net acres in the Northern Midland basin, an area that has seen only limited drilling activity. We expect to continue exploration of this acreage over the next several years, although our position is subject to

meaningful lease expirations through 2015. Our exploration drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- the results of our exploration drilling activities;
- receipt of additional seismic data or other geophysical data or the reprocessing of existing data;
- material changes in oil or natural gas prices;
- the costs and availability of drilling rigs;
- the success or failure of wells drilled in similar formations or which would use the same production facilities;
- availability and cost of capital;
- changes in the estimates of the costs to drill or complete wells; and
- changes to governmental regulations.

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Delays in exploration, cost overruns or unsuccessful drilling results could have a material adverse effect on our business and future growth.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive deposits will not be discovered. We may 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 any leasehold acreage acquired will be profitably developed, that new wells drilled 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.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. 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 rigs and the delivery of equipment; and
- compliance with governmental requirements.

Failure to conduct our oil and gas operations in a profitable manner may result in write downs of our proved reserves quantities, impairment of our oil and gas properties, and a write down in the carrying value of our unproved properties, and over time may adversely affect our growth, revenues and cash flows.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could prevent them from being drilled or delay their drilling. Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system, marketing and transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the identified drilling locations will ever be drilled or if we will be able to produce oil or natural gas from these drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the identified locations are located, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

We may be unable to integrate successfully the operations of future acquisitions with our operations, and we may not realize all the anticipated benefits of these acquisitions. Our business may include producing property acquisitions that would include undeveloped acreage. We can offer no assurance that we will achieve the desired profitability from any acquisitions we may complete in the future. In addition, failure to assimilate recent and future acquisitions successfully could adversely affect our financial condition and results of operations. Our acquisitions may involve numerous risks, including:

- operating a larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new geographic area;
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risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;

- loss of significant key employees from the acquired business:
- diversion of management's attention from other business concerns;
- failure to realize expected profitability or growth;
- failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisition and current operations, which in turn, could negatively impact our results of operations.

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We may fail to fully identify problems with any properties we acquire, and as such, assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities. We are actively seeking to acquire additional acreage in Texas or other regions in the future. 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. Although we conduct a review of properties we acquire which we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify. Such assessments are inexact and their accuracy is inherently uncertain. 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.
Unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our ability to conduct business. There are many operating hazards in exploring for and producing oil and natural gas, including:

- our drilling operations may encounter unexpected formations or pressures, which could cause damage to equipment or personal injury;
- we may experience equipment failures which curtail or stop production;
- we could experience blowouts or other damages to the productive formations that may require a well to be re-drilled or other corrective action to be taken;
- storms and other extreme weather conditions could cause damages to our production facilities or wells.

Because of these or other events, we could experience environmental hazards, including release of oil and natural gas from spills, natural gas-leaks, accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or fracturing fluids, including chemical additives, underground migration, and ruptures.

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

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

We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

Factors beyond our control affect our ability to market production and our financial results. The ability to market oil and natural gas from our wells depends upon numerous factors beyond our control. These factors could negatively affect our ability to market all of the oil or natural gas we produce. In addition, we may be unable to obtain favorable prices for the oil and natural gas we produce. These factors include:

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

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In particular, in areas with increasing non-conventional shale drilling activity, capacity may be limited and it may be necessary for new interstate and intrastate pipelines and gathering systems to be built.
Part of our strategy involves drilling in new or emerging shale formations using horizontal drilling and completion techniques. The results of our planned drilling program in these formations may be subject to more uncertainties than conventional drilling programs in more established formations and may not meet our expectations for reserves or production. The results of our recent horizontal drilling efforts in new or emerging formations, including the Wolfcamp shale, Cline shale, and Mississippian lime in the Permian basin, are generally more uncertain than drilling results in areas that are developed and have established production. Because new or emerging formations have limited or no production history, we are less able to rely on past drilling results in those areas as a basis predict our future drilling results. Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging areas. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, access to gathering systems and takeaway capacity or otherwise, and/or natural gas and oil prices decline, our investment in these areas may not be as economic as we anticipate, we could incur material writedowns of unevaluated properties and the value of our undeveloped acreage could decline in the future.

The loss of key personnel could adversely affect our ability to operate. We depend, and will continue to depend in the foreseeable future, on the services of our senior officers and other key employees, as well as other third-party consultants with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and natural gas from proved properties and maximizing production from oil and natural gas properties. Our ability to retain our senior officers, other key employees and our third party consultants, none of whom are subject to employment agreements, is important to our future success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

We may not be insured against all of the operating risks to which our business is exposed. In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable and may elect none or minimal insurance coverage. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our financial condition and operations.

Competitive industry conditions may negatively affect our ability to conduct operations. We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and gas companies and smaller independents as well as numerous financial buyers, including many that have significantly greater resources. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to procure materials, equipment and services required to explore, develop and operate our properties, including the ability to procure fracture stimulation services on wells drilled; and
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our ability to access pipelines, and the location of facilities used to produce and transport oil and natural gas production.

Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”) establishes federal oversight and regulation of over-the-counter derivatives and requires the Commodity Futures Trading Commission (the “CFTC”) and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions); the CFTC’s final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. The CFTC appealed this ruling but subsequently withdrew its appeal. On November 5, 2013, the CFTC approved a Notice of Proposed Rulemaking designed to implement new position limits regulation. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

The Act provides a limited exception to end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter and authorizes the CFTC to set requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, hedging transactions in the future would become more expensive than we experienced in the past.

We may not have production to offset hedges. Part of our business strategy is to reduce our exposure to the volatility of oil and natural gas prices by hedging a portion of our production. In a typical hedge transaction, we will have the right to receive from the other parties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the other parties this difference multiplied by the quantity hedged. Additionally, we are required to pay the difference between the floating price and the fixed price when the floating price exceeds the fixed price regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production.

By hedging, we may not benefit from price increases. Hedging can prevent us from receiving the full advantage of increases in oil or natural gas prices above the fixed amount specified in a hedge transaction in the case of a swap. We also enter into price “collars” to reduce the risk of changes in oil and natural gas prices. Under a collar, no payments are due by either party so long as the market price is above a floor set in the collar and below a ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to us and if the price is above the ceiling, we pay the counter-party the difference. Another type of hedging contract we have entered into is a put contract. Under a put, if the price falls below the set floor price, the counter-party to the contract pays the difference to us. See “Quantitative and Qualitative Disclosures About Market Risks” for a discussion of our hedging practices.

Our hedging transactions expose us to counterparty credit risk. Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results. Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates, advances to joint interest parties and joint interest receivables. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas accounted for approximately 38% of our total oil and natural gas revenues for the year ended December 31, 2013. We do not require any of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. Joint interest receivables arise from billing entities who own a partial interest in the wells we operate. These entities participate in our wells primarily

based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells.
Compliance with environmental and other government regulations could be costly and could negatively impact production. Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment or otherwise relating to environmental protection. For a discussion of the material regulations applicable to us, see “Regulations.” These laws and regulations may:

- require that we acquire permits before commencing drilling;
- impose operational, emissions control and other conditions on our activities;
- restrict the substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands and wilderness areas; and

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- require measures to remediate or mitigate pollution and environmental impacts from current and former operations, such as cleaning up spills or dismantling abandoned production facilities.

Under these laws and regulations, we could be liable for costs of investigation, removal and remediation, damages to and loss of use of natural resources, loss of profits or impairment of earning capacity, property damages, costs of and increased public services, as well as administrative, civil and criminal fines and penalties, and injunctive relief. We could also be affected by more stringent laws and regulations adopted in the future, including any related climate change, greenhouse gases and hydraulic fracturing. Under the common law, we could be liable for injuries to people and property. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or we may be required to cease production from properties in the event of environmental incidents.

Climate change legislation or regulations restricting emissions of "greenhouse gasses" could result in increased operating costs and reduced demand for the oil and natural gas we produce. The EPA has adopted its so-called "GHG tailoring rule" that phases in federal PSD permit requirements for GHG emissions from new sources and modification of existing sources, federal Title V operating permit requirements for all sources, based upon their potential to emit specific quantities of GHGs. These permitting provisions to the extent applicable to our operations could require us to implement emission controls or other measures to reduce GHG emissions and we could incur additional costs to satisfy those requirements.

In addition, , the EPA requires the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published its amendments to the GHG reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities is required on an annual basis, beginning in 2012 for emissions occurring in 2011, if the total emissions within a basin exceed 25,000 metric tons CO_2 equivalent per year. We will incur costs associated with this monitoring obligation and potentially additional reporting costs if production growth triggers the emission threshold.

In addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states have already taken or have considered legal measures to reduce or measure GHG emissions, often involving the planned development of GHG emission inventories and/or cap and trade programs. Most of these cap and trade programs would require major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. These allowances would be expected to escalate significantly in cost over time. The adoption and implementation of any legislation or regulatory programs imposing GHG reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGS associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects. In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including storms and floods), the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities either because of climate-related damages to our facilities in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect affect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. Should drought conditions occur, our ability to obtain water in sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells for which we are the operator. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result

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in fines, penalties, and remediation costs, among other sanctions and liabilities under federal 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. In March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. A progress report was issued in December 2012, with final results expected in 2014. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative, could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

A committee of the U.S. House of Representatives conducted an investigation of hydraulic fracturing practices. Legislation was introduced before Congress, but not passed to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states and local or regional regulatory authorities have adopted or are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. While we have no operations in either New York or Pennsylvania, any other new laws or regulations that significantly restrict hydraulic fracturing in areas in which we do operate could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect the determination of whether a well is commercially viable. Further, EPA has announced initiatives under the CWA to establish standards of wastewater from hydraulic fracturing and under TSCA to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals, and the BLM has indicated that it will continue with rulemaking to regulate hydraulic fracturing on federal lands. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation. In recent years, the Obama administration’s budget proposals and other proposed legislation have included the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes include, but are not limited to (1) the repeal of the percentage depletion allowance for oil and gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for U.S. production activities and (4) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for or development of, oil and gas within the United States. It is unclear whether any such changes will be enacted or how soon any such changes would become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect the Company’s financial condition and results of operations.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected. Our management, including our Chief Executive Officer and Chief Financial Officer, do not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

We have no plans to pay cash dividends on our common stock in the foreseeable future. We have no plans to pay cash dividends in the foreseeable future. Any future determination as to the declaration and payment of cash dividends will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors deemed relevant by our board of directors. In addition, the terms of our credit facilities prohibit us from paying dividends and making other distributions.

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Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations. Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have not experienced cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

ITEM 1B. Unresolved Staff Comments

None.

3. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material effect on our financial position or results of operations.

ITEM 4. Mine Safety Disclosures

Not applicable.

PART II.

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

Market Information

Our common stock trades on the New York Stock Exchange under the symbol "CPE". The following table sets forth the high and low sale prices per share as reported for the periods indicated.

	Stock Price			
	2013		2012	
	High	Low	High	Low
First quarter	$5.82	$3.62	$7.95	$5.09
Second quarter	4.00	3.19	6.45	3.80
Third quarter	5.49	3.40	6.55	4.11
Fourth quarter	7.60	5.18	6.36	4.05

Holders

As of March 10, 2014 the Company had approximately 3,111 common stockholders of record.

Dividends

We have not paid any cash dividends on our common stock to date and presently do not expect to declare or pay any cash dividends on our common stock in the foreseeable future as we intend to reinvest our cash flows and earnings into our business. The declaration and payment of dividends is subject to the discretion of our Board of Directors and to certain limitations imposed under Delaware corporate law and the agreements governing our debt obligations. The timing, amount and form of dividends, if any, will depend on, among other things, our results of operations, financial condition, cash requirements and other factors deemed relevant by our Board of Directors.

Holders of our Series A preferred stock are entitled to a cumulative dividend whether or not declared, of $5.00 per annum, payable quarterly, equivalent to 10% of the liquidation preference of $50.00 per share. Unless the full amount of the dividends for the Series A Preferred Stock is paid in full, we cannot declare or pay any dividend on our common stock. In addition, certain of our debt facilities contain restrictions on the payment of dividends to the holders of our common stock.

During the fourth quarter of 2013, neither the Company nor any affiliated purchasers made repurchases of Callon's equity securities.

Equity Compensation Plan Information

The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2013 (securities amounts are presented in thousands).

	Outstanding Options		
Plan Category	Number of securities to be issued upon exercise of	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation

	outstanding options		plans
Equity compensation plans approved by security holders	37	$ 13.51	1,192
Equity compensation plans not approved by security holders	15	14.37	—
Total	52	13.75	1,192

For additional information regarding the Company’s benefit plans and share-based compensation expense, see Notes 7 and 8 to the Consolidated Financial Statements.

Performance Graph

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the performance of the Company's common stock relative to four broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

Consistent with the Company's prior year performance graph, the graph below compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the New York Stock Exchange Market Index and New York Stock Exchange Market Index from December 31, 2008, through December 31, 2013. The Company plans to replace these indexes with S&P 500 Index and the SIG Oil Exploration & Production Index, which is believes provides a more meaningful comparison and is reflective of the indexes more commonly used by the Company's peer group. Consequently, these indexes have also been added to the graph below, and we expect will be used in future year's performance graphs.

The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Comparison of Five Year Cumulative Total Return
Assumes Initial Investment of $100
December 2013

	For the Year Ended December 31,					
Company/Market/Peer Group	2008	2009	2010	2011	2012	2013
Callon Petroleum Company	$100.00	$57.69	$227.69	$191.15	$180.77	$251.15
S&P 500 Index - Total Returns	100.00	126.46	145.51	148.59	172.37	228.19
NYSE Composite Index	100.00	128.95	146.69	141.46	164.45	207.85
SIG Oil Exploration & Production Index	100.00	161.62	198.98	180.95	168.41	213.16
Morningstar Group Index	100.00	185.22	194.51	167.95	189.60	216.25

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ITEM 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information about us. The financial information for each of the five years in the period ended December 31, 2013 has been derived from our audited Consolidated Financial Statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of our future results.

	For the year ended December 31,				
	2013	2012	2011	2010	2009
Statement of Operations Data:	(In thousands, except per share amounts)				
Operating revenues:					
Oil and natural gas sales	$102,569	$110,733	$127,644	$89,882	$101,259
Medusa BOEM royalty recoupment (a)	—	—	—	—	40,886
Total operating revenues	$102,569	$110,733	$127,644	$89,882	$142,145
Total operating expenses	$91,905	$100,043	$88,022	$68,692	$68,692
Income (loss) from continuing operations	10,664	10,690	39,622	21,179	73,453
Net income (loss) (b)	4,304	2,747	106,396	8,386	46,796
Earnings (loss) per share ("EPS"):					
Basic	$(0.01)	$0.07	$2.81	$0.29	$2.12
Diluted	$(0.01)	$0.07	$2.76	$0.28	$2.11
Weighted average number of shares outstanding for Basic EPS	40,133	39,522	37,908	28,817	22,072
Weighted average number of shares outstanding for Diluted EPS	40,133	40,337	38,582	29,476	22,200
Statement of Cash Flows Data:					
Net cash provided by operating activities	$54,329	$51,290	$79,167	$100,102	$19,698
Net cash used in investing activities	(79,804)	(93,703)	(91,511)	(59,738)	(43,189)
Net cash provided by (used in) financing activities	27,348	(243)	38,703	(26,252)	10,000
Balance Sheet Data:					
Oil and gas properties, net	$324,187	$269,521	$215,912	$168,868	$130,608
Total assets	423,953	378,173	369,707	218,326	227,991
Long-term debt (c)	75,748	120,668	125,345	165,504	179,174
Stockholders' equity (deficit)	279,094	205,971	201,202	15,810	(80,854)
Proved Reserves Data:					
Total oil (MMBbls)	11,898	10,780	10,075	8,149	6,479
Total natural gas (MMcf)	17,751	19,753	35,118	32,957	19,103
Total proved reserves (MBOE)	14,857	14,072	15,928	13,641	9,663
Standardized measure (d)	$283,946	$231,148	$270,357	$198,916	$135,921

(a) Following the decisions resulting from several court cases brought by another oil and gas company, the court ruled that the BOEM was not entitled to receive these royalty payments. The amount above reflects royalty recoupments for production from the fields 2003 inception through December 31, 2008, which were accrued at December 31, 2009 and paid by the BOEM during 2010.

(b) Net income for 2011 includes $69.3 million of income tax benefit related to the reversal of the Company's deferred tax asset valuation allowance. See Note 10 for additional information.

(c) 2013 and 2012 long-term debt includes a non-cash deferred credit of $5,267 and $13,707, respectively that will be amortized into earnings as a reduction to interest expense over the life of the 13% Senior Notes due 2016. See Note 4 for additional information.

(d) Standardized measure is the future net cash flows related to estimated proved oil and natural gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet. Prices are based on either the preceding 12-months' average price, based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. Future production and development costs are based on current estimates with no escalations. Estimated future cash flows have been discounted to their present values based on a 10% discount rate.

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

General

The following management's discussion and analysis is intended to assist in understanding the principal factors affecting the Company's results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying audited consolidated financial statements, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this filing.

We have been engaged in the exploration, development, acquisition and production of oil and natural gas properties since 1950.

Significant accomplishments for 2013 include:

- Increased 2013 Permian Basin annual production by 38% to 813 MBOE as compared to 2012;
- Exceeded our "exit rate" target production rate for 2013, producing 3,611 BOE/d from our Permian operations in the month of December;
- Increased 2013 Permian Basin proved reserves by 58% to 14.9 MMBOE as compared to 2012;
- Replaced 708% of Permian production with net Permian proved reserve additions, net of revisions;
- Drilled a total of 17 horizontal wells in the Southern Midland Basin, producing from two established zones in the Wolfcamp B and the Wolfcamp A;
- Acquired our Garrison Draw field inclusive of 2,186 net acres and associated production in Reagan County for $11 million, which further added to our inventory of horizontal well locations. Subsequently, we expanded this acreage position to accommodate the drilling of long laterals;
- Accelerated offshore cash flows for onshore redeployment with the sale of our interest in the Medusa and our remaining shelf fields for $100 million before customary purchase price adjustments, and
- Raised $70.0 million from the issuance of Series A Cumulative Preferred Stock,
- Retired 50% of our Senior Notes, improving our cost of capital, and
- Received the Midland Bruno Hanson/Midland College Award for Environmental Excellence recognizing our commitment to strong environmental stewardship in the Permian Basin.

Permian Production Growth and Well Counts

Following the sale of our remaining offshore and Haynesville properties in the fourth quarter of 2013, all of our producing properties are located in the Permian Basin. Our production in the Permian grew 38% in 2013 compared to 2012, increasing to 813 MBOE from 591 MBOE, respectively. Production in 2013 continued to benefit from high oil concentrations including 64% oil and 36% natural gas, which we anticipate to further increase following the sale of our offshore assets.

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	Net Production (MBOE) Twelve Months Ended December 31,			
	2013	2012	Change	% Change
Onshore:				
Southern Midland Basin	612	402	210	52 %
Central Midland Basin	193	189	4	2 %
Northern Midland Basin	8	—	8	100 %
Total Permian	813	591	222	38 %
Offshore:				
Medusa	302	464	(162)	(35)%
Habanero	—	134	(134)	(100)%
Total offshore	302	598	(296)	(49)%
Other:				
Haynesville shale	18	46	(28)	(61)%
Gulf of Mexico shelf and other	280	340	(60)	(18)%
Total other	298	386	(88)	(23)%
Total	1,413	1,575	(162)	(10)%

On average, we operated 1.4 horizontal rigs and one vertical rig in 2013, and drilled a total of 26 gross (22.2 net) wells, of which 1 gross (0.4 net) well was recompleted during the year and 5 gross (4.7 net) were awaiting completion at December 31, 2013.

	Drilled		Completed (a)		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Southern Midland Basin						
Vertical wells	1	1.0	1	1.0	—	—
Horizontal wells	17	15.5	15	13.5	3	3.0
Total	18	16.5	16	14.5	3	3.0
Central Midland Basin						
Vertical wells	5	3.0	7	4.4	—	—
Horizontal wells	2	1.7	—	—	2	1.7
Total	7	4.7	7	4.4	2	1.7
Northern Midland Basin						
Vertical wells	1	1.0	2	1.8	—	—
Horizontal wells	—	—	1	0.8	—	—
Total	1	1.0	3	2.5	—	—
Total	26	22.2	26	21.4	5	4.7
Total vertical wells	7	5.0	10	7.1	—	—
Total horizontal wells	19	17.2	16	14.3	5	4.7
Total	26	22.2	26	21.4	5	4.7

(a) Completions include wells drilled prior to 2013.

Permian Reserve Growth

As of December 31, 2013, our estimated Permian proved reserves increased 58% to 14.9 MMBOE compared to 9.4 MMBOE of Permian proved reserves at year-end 2012. In total, proved reserves increased 6%, or 0.8 MMBOE, to 14.9 MMBOE from 14.1 MMBOE for as of the same date in 2012 as our significant growth in Permian proved reserves was largely offset by the sale of our offshore and Haynesville properties and by the reclassification of previously recorded Permian vertical development proved undeveloped reserves as we focus on horizontal development. Our Permian Basin proved reserves at year-end 2013 were 80% oil and 20% natural gas, compared to 76% oil and 24% natural gas at year-end 2012.

2013 Preferred Equity Offering

On May 30, 2013, the Company issued $75.0 million of 10.0% Series A Cumulative Preferred Stock (the "Preferred Stock") and received $70.0 million net proceeds after deducting the underwriting commissions and offering expenses. We used the proceeds of this equity offering to repay outstanding borrowings under our revolving Credit Facility, to fund accelerated capital expenditures to further develop and evaluate our Permian asset base, and for general corporate purposes.

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Our primary uses of capital have been for the acquisition, development and exploration of oil and natural gas properties. Cash and cash equivalents increased $1.9 million during 2013 to $3.0 million compared to $1.1 million at December 31, 2012. We recently entered into the Amended Credit Facility and Second Lien Facility to support the funding of our ongoing operations. For additional information, see Note 4 to the Consolidated Financial Statements. We believe that, as discussed below, our operating cash flows combined with our bank borrowing ability provides the liquidity necessary to meet our operational cash flow needs.

Liquidity and cash flow:

	For the Year Ended December 31,		
	2013	2012	2011
Net cash provided by operating activities	54.3	51.3	79.2
Net cash used in investing activities	(79.8)	(93.7)	(91.5)
Net cash provided by (used in) financing activities	27.3	(0.3)	38.7
Net change in cash	1.8	(42.7)	26.4

Operating Activities. For the year ended December 31, 2013, net cash provided by operating activities was $54.3 million, compared to $51.3 million for the same period in 2012. The increase was related primarily to a 15% decrease in lease operating expenses coupled with a 3% increase in the average sales price on an equivalent basis partially offset by lower revenues as oil and natural gas production decreased 7% and 16%, respectively. Production and realized prices are discussed below in Results of Operations.

Investing Activities. For the year ended December 31, 2013, net cash used in investing activities was $79.8 million as compared to $93.7 million for the same period in 2012. The net $13.9 million decrease in cash used in investing activities is primarily attributable to a $50.1 million increase in proceeds from the sale of mineral interests and equipment offset by a 26.4 million increase in capital expenditures related to development activity on our Permian basin acreage and $10.9 million for producing property acquisitions. The $50.1 million increase in the previously mentioned proceeds relates to the proceeds in 2013 of $90.0 million, primarily attributable to the sale of our Medusa and offshore properties compared to proceeds in 2012 of $39.9 million, primarily related to the sale of our Habanero offshore property, which are both discussed below and in Note 12 to the financial statements. The $26.4 million increase in capital expenditures included the costs associated with expanding to a two-rig drilling program and the acquisition of the Garrison Draw property.

2014 Budgeted Capital Expenditures

In early February 2014, we announced our operational capital budget for 2014:

		Gross Wells	
Category	($ millions)	Drill	Complete
Horizontal wells	$155	27	26
Vertical wells	15	9	8
Facilities and equipment	15		
Total operational capital	$185		

We expanded our horizontal pad development efforts from two to four fields in late 2013, adding Carpe Diem in Midland County and Garrison Draw in Reagan County. We expect our 2014 horizontal drilling program will be primarily focused on program development of established Upper and Lower Wolfcamp zones in the Southern and Central Midland Basin, but will also include two wells in the Southern Midland Basin to evaluate the Wolfcamp A shale and a test of the Lower Spraberry shale formation in the Central Midland Basin. In addition, we anticipate the average lateral length of our horizontal wells in 2014 to be approximately 7,000' per well.

Planned vertical drilling activity is anticipated to be limited to five deep Wolfberry wells in the Pecan Acres field, one well in the Garrison Draw field. We have included three vertical exploration wells in the Northern Midland Basin, the timing and location of which being subject to change as results are evaluated during the course of 2014.

In addition to the operational capital expenditures above, we budgeted approximately $25 million for capitalized expenses and certain retained plugging abandonment expenses related to divested Gulf of Mexico shelf assets.

Our 2014 capital program is 100% operated and, as a result, the amount and timing of these capital expenditures are largely discretionary depending on commodity prices and other factors. We expect to fund our 2014 capital program through a combination of cash flow from operations, bank borrowings and term debt issuance, including our recently executed Second Lien Facility.

Financing Activities. For the year ended December 31, 2013, net cash provided by financing activities was $27.3 million compared to cash used by financing activities of $0.3 million during the same period of 2012. Net cash provided by financing activities for 2013 included proceeds of $70.4 million, net from our Preferred Stock offering (see Note 9 for additional information) and a $12 million draw, net on our Credit Facility offset by the $50 million redemption of our Senior Notes, and approximately $4.6 million in preferred stock dividends.

Senior Secured Credit Facility ("Credit Facility")

The Company's $200 million Credit Facility, for which Regions Bank serves as the Administrative Agent, matures March 15, 2016 and includes Citibank, NA, IberiaBank, Whitney Bank and OneWest Bank, FSB as participating lenders. As of December 31, 2013, the Company's Credit Facility had an approved borrowing base at December 31, 2013 of $83 million. The Credit Facility was secured by mortgages covering the Company's major producing fields. As of December 31, 2013, the balance outstanding on the Credit Facility was $22 million with an interest rate of 2.92%, calculated as the London Interbank Offered Rate (LIBOR), plus a tiered rate ranging from 2.5% to 3.0%, which is determined by utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly.

Subsequent to December 31, 2013, the Company amended its existing Credit Facility as discussed below. Additionally, the Company executed the Second Lien Facility also discussed below.

Amended Credit Facility (the "Amended Credit Facility") and Second Lien Term Loan Facility (the "Second Lien Facility")

On March 11, 2014, we entered into an amended senior secured revolving credit facility (the "Amended Credit Facility") in the amount of $500 million with JPMorgan Chase Bank, N.A. as Administrative Agent ("J.P. Morgan"). The Credit Facility will have an initial borrowing base amount of $95 million and a maturity date of March 11, 2019. In conjunction with the Amended Credit Facility, we entered into a senior secured second lien term loan facility (the "Second Lien Facility") in an aggregate amount of up to $125 million with J.P. Morgan as Administrative Agent and with a maturity date of September 11, 2019. See Note 4 for additional information.

13% Senior Notes due 2016 (the “Senior Notes”) and Deferred Credit

As of December 31, 2013, following a $48.5 million principal redemption in December 2013, we had approximately $48.5 million principal amount of the 13% Senior Notes due 2016 outstanding with interest payable quarterly.

Contractual Obligations

The following table includes the Company's current contractual obligations and purchase commitments, at which time the Company had no product delivery commitments:

(amounts in thousands)	Payments due by Period				
	Total	< 1 Year	Years 2 - 3	Years 4 - 5	>5 Years
13% Senior Notes	$48,481	$—	$48,481	$—	$—
Drilling rig leases and related (a)	42,482	19,732	22,750	—	—
Office space lease and other commitments	3,208	618	1,096	717	777
Total	$94,171	$20,350	$72,327	$717	$1,124

(a) The <1 Year column includes $2,055 related to the early termination provisions of one of the Company's horizontal drilling rigs (See Note 13), which the Company replaced with a different horizontal rig, and the amount assumes the lessor is unable to re-charter the rig and staffing personnel to another lessee. Should the lessor re-charter the rig and its related personnel to a new lessee, the $2,055 would be reduced by the value of the new lessee's rentals. Also includes an anticipated contract renewal of our Cactus 1 Rig lease.

Income Taxes

The Company's income tax expense varies from the statutory rate primarily due to the effect of state taxes, non deductible compensation under Section 162(m) and restricted stock offset by percentage depletion. Prior to 2012, we carried a full valuation allowance against our net deferred tax asset. The income tax benefit of $69.3 million in 2011 resulted primarily from the reversal of the valuation allowance established in 2008 against our net deferred tax assets. For additional information, see the Income Tax discussion included below in Results of Operations and Note 10 to the Consolidated Financial Statements.

Results of Operations

The following table sets forth certain unaudited operating information with respect to the Company’s oil and natural gas operations for the periods indicated:

	For the Year Ended December 31,						
	2013	2012	Change	% Change	2011	Change	% Change
Net production:							
Oil (MBbls)	911	977	(66)	(7)%	996	(19)	(2)%
Natural gas (MMcf)	3,011	3,588	(577)	(16)%	5,081	(1,493)	(29)%
Total production (MBOE)	1,413	1,575	(162)	(10)%	1,843	(268)	(15)%
Average daily production (BOE)	3,871	4,303	(432)	(10)%	5,049	(746)	(15)%
Average realized sales price (see below):							
Oil (Bbl)	$97.65	$98.86	$(1.21)	(1)%	$101.34	$(2.48)	(2)%
Natural gas (Mcf)	4.52	3.94	0.58	15%	5.25	(1.31)	(25)%
Total (BOE)	72.59	70.31	2.28	3%	69.26	1.05	2%
Oil and natural gas revenues (in thousands):							
Oil revenue	$88,960	$96,584	$(7,624)	(8)%	$100,962	$(4,378)	(4)%
Natural gas revenue	13,609	14,149	(540)	(4)%	26,682	(12,533)	(47)%
Total	$102,569	$110,733	$(8,164)	(7)%	$127,644	$(16,911)	(13)%
Additional per BOE data:							
Sales price	$72.59	$70.31	$2.28	3%	$69.26	$1.05	2%
Lease operating expense	(14.00)	(14.81)	0.81	5%	(9.92)	(4.89)	49%
Production taxes	(2.92)	(2.05)	(0.87)	(42)%	(1.12)	(0.93)	83%
Operating margin	$55.67	$53.45	$2.22	4%	$58.22	$(4.77)	(8)%

Below is a reconciliation of the average NYMEX price to the average realized sales price per Bbl of oil and Mcf of natural gas:

Average NYMEX oil price ($/Bbl)	$97.96	$94.19	$3.77	4%	$95.14	$(0.95)	(1)%
Basis differential and quality adjustments (a)	0.12	3.97	(3.85)	(97)%	7.58	(3.61)	(48)%
Transportation	(0.43)	(0.75)	0.32	43%	(1.00)	0.25	(25)%
Hedging (b)	—	1.45	(1.45)	100%	(0.38)	1.83	100%
Average realized oil price ($/Bbl)	$97.65	$98.86	$(1.21)	(1)%	$101.34	$(2.48)	(2)%
Average NYMEX natural gas price ($/MMBtu)	$3.73	$2.82	$0.91	32%	$4.03	$(1.21)	(30)%
Basis differential and quality adjustments (c)	0.79	1.12	(0.33)	(29)%	1.22	(0.10)	(8)%
Average realized natural gas price ($/Mcf)	$4.52	$3.94	$0.58	15%	$5.25	$(1.31)	(25)%

(a)

Oil prices for production from our two divested deepwater fields reflect a premium over NYMEX pricing based on Mars WTI differential for Medusa production, prior to the sale of Medusa in December 2013, and Argus Bonita WTI differential for Habanero production, prior to the sale of Habanero during December 2012.

(b) As discussed in Note 5, the Company discontinued hedge accounting beginning with derivative contracts executed on January 1, 2012. Consequently, the gain or loss on derivative contracts, settled is now included in the statement of operations within Loss (Gain) on derivative contracts. The amounts reported above reflect the realized portion of derivative contracts designated as cash flow hedges.

(c) Natural gas prices exceeded the related NYMEX prices, which are quoted on an MMBtu basis, primarily due to the value of the NGLs in our liquids-rich natural gas stream, primarily from our Permian basin production.

Revenues

The following tables are intended to reconcile the change in oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume, changes in the underlying commodity prices and the impact of our hedge program. (in thousands)

	Oil	Natural Gas	Total
Revenues for the year ended December 31, 2010	$65,243	$24,639	$89,882
Volume increase	10,406	952	11,358
Price increase	25,688	1,091	26,779
Impact of hedges decrease	(375)	—	(375)
Net increase in 2011	35,719	2,043	37,762
Revenues for the year ended December 31, 2011	$100,962	$26,682	$127,644
Volume decrease	(1,926)	(7,840)	(9,766)
Price decrease	(3,872)	(4,693)	(8,565)
Impact of hedges increase	1,420	—	1,420
Net decrease in 2012	(4,378)	(12,533)	(16,911)
Revenues for the year ended December 31, 2012	$96,584	$14,149	$110,733
Volume decrease	(10,065)	(540)	(10,605)
Price increase	2,441	—	2,441
Net decrease in 2013	(7,624)	(540)	(8,164)
Revenues for the year ended December 31, 2013	$88,960	$13,609	$102,569

Oil Revenue

For the year ended December 31, 2013, oil revenues of $89.0 million decreased $7.6 million, or 8%, compared to revenues of $96.6 million for the year ended December 31, 2012. Lower production from our offshore properties, primarily related to the sale of Habanero field in December 2012 and our Medusa and shelf properties in the fourth quarter of 2013, drove the revenue decline. Also contributing to the production decline were 20 days of down time for scheduled downstream pipeline maintenance at our Medusa field in the second quarter of 2013, approximately five days of production downtime at our key producing Permian Basin fields in the fourth quarter of 2013 due to severe winter weather causing electricity outages and the extended curtailment of trucking capacity to transport offtake and due to normal and expected declines from other producing wells. Collectively, these declines were offset by the 222 MBbls increase in our oil production from our Permian properties.

For the year ended December 31, 2012, oil revenues of $96.6 million decreased $4.4 million, or 4%, compared to revenues of $101.0 million for the year ended December 31, 2011. A decrease in commodity prices and production resulted in decreased oil revenue. The average price realized decreased 2% to $98.86 per barrel compared to $101.34 for the same period of 2011. Similarly, production decreased by 2% to 977 MBbls compared to 996 MBbls during the same period in 2011. Oil prices for production from our two deepwater fields are adjusted and reflect a premium over NYMEX pricing based on Mars WTI differential for Medusa production and Bonita WTI differential for Habanero production. Production decreases relate primarily to the down-time at the Habanero and Medusa fields and the normal and expected declines from our other offshore properties. These production declines were offset by production from our new Permian wells, 22 vertical and two horizontal, brought onto production during 2012.

Natural Gas Revenue

For the year ended December 31, 2013, natural gas revenues of $13.6 million represented a decrease of 4%, or $0.5 million, compared to natural gas revenues of $14.1 million for the year ended December 31, 2012. While the average realized price increased 15%, a 16% decrease in production reduced total revenue. The production declines were primarily attributable to the shut-in of production of our Mobile Bay 908 property, the sale of our offshore fields, the sale of our Haynesville well in the fourth quarter of 2013 as well as normal and expected declines from our existing wells. Offsetting these declines was a 248 MMcf increase in horizontal well production from our Permian properties.

For the year ended December 31, 2012, natural gas revenues of $14.1 million represented a decrease of 47%, or $12.5 million, when compared to natural gas revenues of $26.7 million for the year ended December 31, 2011. Natural gas production decreased 29%, driven primarily by down time at our Haynesville well, which was shut-in for 70 days during the first quarter of 2012 due to well interference from an offsetting well, and due to down time at our East Cameron 257 well, which was suspended in the fourth quarter of 2011 due to a natural gas leak in an upstream section of the Stingray Pipeline that transports production volumes from the field. Also contributing to the decline was down-time at our Habanero and Medusa fields and normal and expected declines in natural gas production from our offshore and Haynesville wells. In addition to production decreases, the average realized price decreased 25% to $3.94 per Mcf compared to an average realized price of $5.25 per Mcf in 2011. Our natural gas prices on an MMBtu equivalent basis exceeded the related NYMEX prices primarily due to the value of the NGLs in our natural gas stream, primarily from our Permian basin and deepwater production.

Operating Expenses

Principal components of our cost structure

Lease operating expenses. These are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our oil and natural gas properties.

Production taxes. Production taxes include severance and ad valorem taxes. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and gas properties.

Depreciation, depletion and amortization. Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units of production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years.

General and administrative. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other fees for professional services and legal compliance.

Accretion expense. The Company is required to record its estimate of the fair value of liabilities for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligations and reported as accretion expense within operating expenses in the consolidated statements of operations.

	For the Year Ended December 31,				Total Change		BOE Change	
	2013	Per BOE	2012	Per BOE	$	%	$	%
Lease operating expenses	$19,779	$14.00	$23,330	$14.81	$(3,551)	(15)%	$(0.81)	(5)%
Production taxes	4,133	2.92	3,224	2.05	909	28%	0.87	42%
Depreciation, depletion and amortization	43,967	31.12	49,701	31.56	(5,734)	(12)%	(0.44)	(1)%
General and administrative	20,534	14.53	20,358	12.93	176	1%	1.6	12%
Accretion expense	1,785	1.26	2,253	1.43	(468)	(21)%	(0.17)	(12)%
Impairment of other property and equipment	1,707	1.21	1,177	0.75	530	45%	0.46	100%
Total operating expenses	$91,905		$100,043					

	For the Year Ended December 31,				Total Change		BOE Change	
	2012	Per BOE	2011	Per BOE	$	%	$	%
Lease operating expenses	$23,330	$14.81	$18,285	$9.92	$5,045	28%	$4.89	49%
Production taxes	3,224	2.05	2,062	1.12	1,162	56%	0.93	83%
Depreciation, depletion and amortization	49,701	31.56	48,701	26.42	1,000	2%	5.14	19%
General and administrative	20,358	12.93	16,636	9.03	3,722	22%	3.90	43%
Accretion expense	2,253	1.43	2,338	1.27	(85)	(4)%	0.16	13%
Impairment of other property and equipment	1,177	0.75	—	—	1,177	100%	0.75	100%
Total operating expenses	$100,043		$88,022					

Lease Operating Expenses (LOE)

For the year ended December 31, 2013, LOE of $19.8 million decreased 15%, or $3.6 million, compared to $23.3 million for the year ended December 31, 2012. The decrease was primarily due to $3.4 million of remediation costs on our Haynesville well in 2012, for which we had no similar costs in 2013, and an estimated decrease of $3.2 million of LOE resulting from the previously discussed sale of our interests in Habanero, Medusa, the Medusa Spar LLC, our Haynesville property and substantially all our remaining shelf properties. These decreases were partially offset by $3.0 million in LOE costs related to the growth in Permian production and operations, including an increase in workover expenses associated with accelerated horizontal well activity.

For the year ended December 31, 2012, LOE of $23.3 million increased 28%, or $5.0 million, compared to $18.3 million for the year ended December 31, 2011. The increase was primarily due to $3.0 million in costs related to growth in the number of wells producing from Permian Basin properties and $3.3 million in remediation work at our Haynesville well in 2012 for which we had no similar costs in 2011. These increases were partially offset by a $1.3 million decline in LOE for our deepwater properties due to lower throughput charges as a result of reduced production volumes.

Production Taxes

For the year ended December 31, 2013, production taxes of $4.1 million increased 28%, or $0.9 million, compared to $3.2 million for the year ended December 31, 2012. The increase was predominantly attributable to an increase of onshore production subject to these taxes and a decline in offshore production, resulting from the sale of our Gulf of Mexico position in 2013, which is exempt from production taxes.

For the year ended December 31, 2012, production taxes of $3.2 million increased 56%, or $1.2 million, compared to $2.1 million for the year ended December 31, 2011. The increase was predominantly attributable to an increased proportion of onshore production subject to these taxes relative to offshore production, which was predominantly exempt from production taxes.

Depreciation, Depletion and Amortization (DD&A)

For the year ended December 31, 2013, DD&A of $31.12 per BOE was relatively flat compared to $31.56 per BOE for the year ended December 31, 2012.

DD&A for the year ended December 31, 2012 increased 19% per BOE to $31.56 per BOE compared to $26.42 per BOE for the year ended December 31, 2011. Increases in the DD&A rate are attributable to our planned exploration and development expenditures related to our onshore reserve development including the ongoing onshore development cost increases in the Permian Basin area.

General and Administrative, net of amounts capitalized (G&A)

G&A remained relatively flat at $20.5 million (including $6.4 million non-cash) for the year ended December 31, 2013 compared to $20.4 million (including $4.7 million non-cash) for the same period of 2012. The $0.1 million increase was due to an increase in non-cash charges of $1.7 million related to incentive compensation share-based instruments offset by a $1.6 million decrease primarily related to non-recurring employee-related expenses including early retirement and severance expense incurred in 2012. The non-cash portions primarily relate to our liability-based incentive compensation share based instruments (see Notes 7 and 8) and to depreciation and amortization expense (see Note 2).

For the year ended December 31, 2012, G&A, increased $3.7 million, or 22%, to $20.4 million (including $4.7 million non-cash) from $16.6 million (including $3.2 million non-cash) for the same period of 2011. The increase is due mainly to $1.6 million in costs for non-recurring employee-related expenses including early retirement and severance expense for which we had no expense during 2011. Additionally, we incurred an increase in non-cash charges of $1.2 million related to incentive compensation share-based instruments awarded during 2012. The remaining increase related primarily to higher compensation-related expenses including the costs associated with employing staff to support our onshore growth and 100% operated Permian production, as well as relocation and related costs.

Accretion Expense (ARO)

Accretion expense related to our asset retirement obligation decreased 21% for the year ended December 31, 2013 compared to the same periods of 2012. Accretion expense correlates directionally with the Company's ARO which was $6.7 million at December 31, 2013 versus $13.3 million at December 31, 2012. See Note 11 for additional information regarding the Company's ARO.

For the year ended December 31, 2012, accretion expense decreased 4% for the year ended December 31, 2012 compared to the same periods of 2011. At December 31, 2012, our ARO of $13.3 million was lower than the $13.9 million ARO at December 31, 2011.

Impairment of Other Property and Equipment

During 2012 and 2013, the Company recorded a write-down of the value of certain assets acquired in 2011 as part of a settlement reached with a former joint interest partner on a deepwater project. For information concerning the impairment of these assets, please see Note 13 to the Consolidated Financial Statements.

Other (Income) Expense

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our credit facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense. The amortization of the deferred credit related to our 13% Senior Notes is recorded as an offset to interest expense.

Gain/Loss on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of oil. This amount represents the (i) gain (loss) related to derivatives, net of settlement that relate to our open derivative contracts as commodity prices change and commodity derivative contracts expire or new ones are entered into and (ii) gains (losses) on derivatives, settled that is equal to the summation of gains and losses on positions that have settled within the period. We provide a reconciliation of the these components of the gain/loss on derivative contracts in Note 5.

Income tax expense. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. When appropriate based on our analysis, we record a valuation allowance for deferred tax assets when it is more likely than not that the deferred tax assets will not be realized.

	For the Year Ended December 31,						
	2013	2012	$ Change	% Change	2011	$ Change	% Change
Interest expense	$6,094	$9,108	$(3,014)	(33)%	$11,717	$(2,609)	(22)%
Gain on early extinguishment of debt	(3,696)	(1,366)	(2,330)	171%	(1,942)	576	(30)%
Gain on acquired equipment	—	—	—	—%	(5,041)	5,041	(100)%
Loss (gain) on derivative contracts	1,360	(1,717)	3,077	(179)%	—	(1,717)	100%
Other income	(485)	(79)	(406)	514%	(1,426)	1,347	(94)%
Total other expenses, net	$3,273	$5,946			$3,308		
Income tax expense (benefit)	$3,104	$2,223	$881	(40)%	$(69,283)	$71,506	103%
Equity in earnings of Medusa Spar LLC	17	226	(209)	(92)%	799	(573)	(72)%
Preferred stock dividends	(4,627)	—	(4,627)	100%	—	—	—%

Interest Expense

Interest expense on Callon's debt obligations decreased 3.0 million to $6.1 million for the year ended December 31, 2013 compared to $9.1 million for the same period of 2012. The decrease was related primarily to an additional $2.3 million of interest capitalized in 2013 versus 2012, to approximately $0.3 million of reduced interest payments attributable to the redemption of $48.5 million principal of the Company's Senior Notes in December 2013 and to $0.1 million of additional deferred credit amortization recognized in 2013 compared with 2012. The additional capitalized interest was related to a higher balance year-over-year in average unevaluated oil and natural gas properties following the purchase of additional unevaluated acreage with exploration costs in the Permian Basin.

Interest expense on Callon's debt obligations decreased 22% to $9.1 million for the year ended December 31, 2012 compared to $11.7 million for the same period of 2011. The decrease was related primarily to the redemption of $10 million principal of Senior Notes during June 2012 in addition to a $1.5 million increase in capitalized interest compared to 2011, partially offset by interest expense related to increased borrowings under our Credit Facility and decreases in the deferred credit amortization. The increase in capitalized interest was related to a higher balance year-over-year in average unevaluated oil and natural gas properties, mentioned above.

(Gain) Loss on Early Extinguishment of Debt

During December 2013, the Company redeemed $53.8 million carrying value of its Senior Notes using a portion of the proceeds from the Company's May 2013 preferred equity offering. The $53.8 million of carrying value included $48.5 million of principal value and $5.3 million of unamortized deferred credit. The Company recognized a net gain of $3.7 million on the early extinguishment of debt, comprised of the recognition of $5.3 million in deferred credit, offset by $1.6 million of redemption expenses. See Note 4 for additional information concerning the gain on early extinguishment of debt.

During June 2012, the Company redeemed $10 million of its Senior Notes with a carrying value of $11.6 million, including $1.6 million of the Senior Notes' deferred credit. The Company recognized a net gain of $1.4 million on the early extinguishment of debt, comprised of the recognition of $1.6 million in deferred credit, offset by $0.2 million of redemption expenses.

Gain on Acquired Equipment

See Note 13 for additional information concerning the gain on acquired equipment.

Loss (Gain) on Derivative Contracts

Beginning in 2012, the Company elected to no longer designate its derivative contracts as accounting hedges. For the year ended December 31, 2013, net losses on mark-to-market derivative instruments, net of settlements were $1.4 million, compared to $1.7 million gain in 2012. See Notes 5 and 6 for a reconciliation of the components of the Company’s derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Income Tax Expense (Benefit)

The income tax expense of $3.1 million in 2013 resulted primarily from pre-tax income earnings of $7.4 million. The effective tax rate of 42% in 2013 and 47% in 2012 differed from the federal income tax rate of 35% primarily due to the effect of state taxes, non-deductible compensation under Section 162(m) and restricted stock offset by percentage depletion. See Note 10 for a discussion of our effective tax rate. Prior to 2012, we carried a full valuation allowance against our net deferred tax asset. The income tax benefit of $69.3 million in 2011 resulted primarily from the reversal of the valuation allowance established in 2008 against our net deferred tax assets as we achieved income on an aggregate basis for a cumulative three-year period and expect to generate the taxable income necessary to fully utilize the deferred tax assets prior to their expiration. For additional information, see Note 11 to the Consolidated Financial Statements.

Preferred Stock Dividends

Preferred Stock dividends for the year ended December 31, 2013 increased $4.6 million compared to the same period of 2012 in which we had no dividend expense. The expense is reflective of the Preferred Stock being outstanding only since its issuance on May 30, 2013, resulting in a reduced stub period payment during the second quarter of 2013.

Summary of Significant Accounting Policies and Critical Accounting 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 GAAP. 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 use. 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 GAAP. We also describe the most significant estimates and assumptions we make in applying these policies. See Note 2 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for a discussion of additional accounting policies and estimates made by management.

Property and Equipment

The Company utilizes the full-cost method of accounting for its oil and natural gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves, including certain overhead costs, are capitalized into the “full-cost pool.” The amounts capitalized into the full-cost pool are depleted (charged against earnings) using the unit-of-production method. The full-cost method of accounting for our proved oil and natural gas properties requires that the Company makes estimates based on its assumptions of future events that could change. These estimates are described below.

Depreciation, Depletion and Amortization (DD&A) of Oil and Natural Gas Properties

The Company calculates depletion by using the depletable base, equal to the net capitalized costs in our full-cost pool plus estimated future development costs, and the estimated net proved reserve quantities. Capitalized costs added to the full-cost pool include the following:

- costs of drilling and equipping productive wells, dry hole costs, acquisition costs of properties with proved reserves, delay rentals and other costs related to exploration and development of our oil and natural gas properties;
- payroll costs including the related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and natural gas properties as well as other directly identifiable general and administrative costs

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associated with such activities. Such capitalized costs do not include any costs related to the production of oil and natural gas or general corporate overhead;

- costs associated with unevaluated properties, those lacking proved reserves, are excluded from the depletable base. These unevaluated property costs are added to the depletable base at such time as wells are completed on the properties, the properties are sold or the Company determines these costs have been impaired. The Company's determination that a property has or has not been impaired (which is discussed below) requires assumptions about future events;

- estimated costs to dismantle, abandon and restore properties that are capitalized to the full-cost pool when the related liabilities are incurred (see also the discussion below regarding Asset Retirement Obligations);

- estimated future costs to develop proved properties are added to the full-cost pool for purposes of the DD&A computation. The Company uses assumptions based on the latest geologic, engineering, regulatory and cost data available to it to estimate these amounts. However, the estimates made are subjective and may change over time. The Company's estimates of future development costs are reviewed at least annually and as additional information becomes available; and

- capitalized costs included in the full-cost pool plus estimated future development costs are depleted and charged against earnings using the unit-of-production method. Under this method, the Company estimates the proved reserves quantities at the beginning of each accounting period. For each BOE produced during the period, the Company records a depletion charge equal to the amount included in the depletable base (net of accumulated depreciation, depletion and amortization) divided by our estimated net proved reserve quantities.

Because the Company uses estimates and assumptions to calculate proved reserves (as discussed below) and the amounts included in the depletable base, our depletion rates may materially change if actual results differ from these estimates.

Ceiling Test

Under the full cost method of accounting, the Company compares, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and natural gas properties net of related deferred taxes. The Company refers to this comparison as a "ceiling test." If the net capitalized costs of proved oil and natural gas properties exceed the estimated discounted (at 10%) future net cash flows from proved reserves, the Company is required to write-down the value of its oil and natural gas properties to the value of the discounted cash flows. Estimated future net cash flows from proved reserves are based on a twelve-month average pricing assumption and include consideration of existing cash flow hedges. Given the volatility of oil and natural gas prices, it is reasonably possible that the Company's estimates of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and natural gas properties could occur in the future. See Notes 2 and 12 for additional information regarding the Company's oil and natural gas properties.

Estimating Reserves and Present Value of Estimated Future Net Cash Flows

Estimates of quantities of proved oil and natural gas reserves, including the discounted present value of estimated future net cash flows from such reserves at the end of each quarter, are based on numerous assumptions, which are likely to change over time. These assumptions include:

- the prices at which the Company can sell its oil and natural gas production in the future. Oil and natural gas prices are volatile, but we are required to assume that they remain constant, using the twelve-month average pricing assumption. In general, higher oil and natural gas prices will increase quantities of proved reserves and the present value of estimated future net cash flows from such reserves, while lower prices will decrease these amounts; and

- the costs to develop and produce the Company's reserves and the costs to dismantle its production facilities when reserves are depleted. These costs are likely to change over time, but we are required to assume that they remain constant. Increases in costs will reduce estimated oil and natural gas quantities and the present value of estimated future net cash flows, while decreases in costs will increase such amounts.

Changes in these prices and/or costs will affect the present value of estimated future net cash flows more than the estimated quantities of oil and natural gas reserves for the Company's properties that have relatively short productive lives.

In addition, the process of estimating proved oil and natural gas reserves requires that the Company's independent and internal reserve engineers exercise judgment based on available geological, geophysical and technical information. We have described the risks associated with reserve estimation and the volatility of oil and natural gas prices under "Risk Factors."

Sales of oil and natural gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Unproved Properties

Costs, including capitalized interest, associated with properties that do not have proved reserves are excluded from the depletable base, and are included in the line item "Unevaluated properties excluded from amortization." Unproved property costs are transferred to the depletable base when wells are completed on the properties or the properties are sold. In addition, the Company is required to determine whether its unproved properties are impaired and, if so, include the costs of such properties in the depletable base. The Company determines whether an unproved property is impaired by periodically reviewing its exploration program on a property-by-property basis. This determination may require the exercise of substantial judgment by management.

Asset Retirement Obligations

We are required to record its estimate of the fair value of liabilities for obligations associated with the retirement of tangible long-life assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligation and reported as accretion expense within operating expenses in the Consolidated Statements of Operations. See Note 11 for additional information.

Derivatives

To manage oil and natural gas price risk on a portion of our planned future production, we have historically utilized commodity derivative instruments (including collars, swaps, puts, and other structures) on approximately 50% of our projected production volumes in any given year. We do not use these instruments for trading purposes. Settlement of derivative contracts are generally based on the difference between the contract price and prices specified in the derivative instrument and a NYMEX price or other cash or futures index price.

Beginning in 2012, we elected to no longer designate derivative contracts executed after January 1, 2012 as accounting hedges under FASB ASC 815-20-25. As such and beginning with derivative contracts executed during 2012, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market through earnings at the end of each period. Gains and losses on derivatives that are not designated as hedges are recorded in earnings as a component of gain (loss) on derivative contracts. Within gain (loss) on derivative contracts line in the statement of operations are gains (losses) on derivatives, net of settlement and gains (losses) on derivatives, settled.

Derivative contracts that were entered into at and prior to December 31, 2011 were accounted for as cash flow hedges, and were recorded at fair market value on its consolidated balance sheet. Changes in fair value were recorded through other comprehensive income (loss), net of tax, in stockholders' equity. The changes in fair value related to ineffective derivative contracts were recognized as derivative expense (income). The estimated fair value of our derivative contracts is based upon closing exchange prices on NYMEX and in the case of collars and floors, the time value of options. For additional information regarding derivatives and their fair values, see Notes 5 and 6 to the Consolidated

Financial Statements and Part II, Item 7A Commodity Price Risk.

Income Taxes

The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state tax jurisdictions. We recognize current tax expense based on estimated taxable income for the current period and the applicable statutory tax rates. We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and other tax carryforwards. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). See Note 10 for additional information regarding Income Taxes.

Recent Accounting Standards

Various accounting standards and interpretations were issued in 2013 with effective dates subsequent to December 31, 2013. We have evaluated the recently issued accounting pronouncements that are effective in 2014 and believe that none of them will have a material effect on our financial position, results of operations or cash flows when adopted. For a discussion of recently issued accounting standards, see Note 2 to the Consolidated Financial Statements.

In February 2013, the Financial Accounting Standards Board issued an Accounting Standards Update (ASU) that clarified the reclassification requirements from accumulated other comprehensive income to net income. This ASU requires disclosure of amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present either on the face of the financial statements or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount is reclassified in its entirety to net income in the same reporting period. For amounts not reclassified in their entirety to net income, an entity is required to cross-reference to the related note on the face of the financial statements for additional information. Callon adopted this guidance effective January 1, 2013, which did not have a material impact on its financial statements.

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risks

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

Commodity Price Risk

The Company's revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our oil and natural gas, which have historically been very volatile due to unpredictable events such as economic growth or retraction, weather and climate, changes in supply and government actions. Oil and natural gas price declines and volatility could adversely affect the Company's revenues, cash flows and profitability. Price volatility is expected to continue. Using the Company's annual sales volumes for 2013, excluding the effects of the Company's hedging program, a 10% decline in the NYMEX price of oil and natural gas would have reduced our revenues by approximately $8.9 million and $1.2 million, respectively.

While the Company does not enter into derivative transactions for speculative purposes, the Company sometimes utilizes price collars, swaps, puts and other structures to reduce the risk of changes in oil and natural gas prices. Under a collar arrangements, no payments are due by either party as long as the market price is above the floor price and below the ceiling price set in the collar. If the price falls below the floor, the counterparty to the collar pays the difference to Callon, and if the price rises above the ceiling, Callon pays the difference to the counterparty. Fixed price swaps reduce the Company's exposure to decreases in commodity prices, while simultaneously limiting the benefit the Company might otherwise have received from any increases in commodity prices. The Company's derivatives policy also allows Callon to, at its discretion, purchase or sell puts. Purchased puts reduce the Company's exposure to decreases in prices of the hedged commodity while allowing realization of the full benefit from any increases those prices. If the commodity price falls below the put price, the counter-party pays the difference to Callon. Conversely, sold puts expose the Company to risk whereby Callon would pay its counter-party if prices fall below the put price. See Note 5 to the Consolidated Financial Statements for a description of our hedged position at December 31, 2013.

Interest Rate Risk

On December 31, 2013, the majority of the Company's debt consisted of its fixed-rate 13% Senior Notes. However, we are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility and our Second Lien Facility into which we entered during March 2014. As of December 31, 2013, the weighted average interest rate on our Credit Facility borrowings was 2.9%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our net income of approximately $0.2 million based on the $22 million outstanding in the aggregate under our Credit Facility on December 31, 2013.

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Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from derivatives financial contracts, joint interest receivables and the receivables from the sale of our oil and natural gas production, which we market to energy marketing companies.

At December 31, 2013 our receivables resulting from derivative financial contracts was approximately $0.1 million. Our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. The counterparties on our derivative instruments currently in place are lenders under our revolving credit facility. We are likely to enter into additional derivative instruments with these or other lenders under our revolving credit facility, representing institutions with an investment grade ratings. We have existing International Swap Dealers Association Master Agreements (“ISDA Agreements”) with our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. At December 31, 2013 we had a net derivative asset position of $0.1 million and a net derivative liability position of $1.1 million.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At December 31, 2013 our joint interest receivables were approximately $4.4 million.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require any of our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the year ended December 31, 2013, three purchasers accounted for more than 10% of our revenue: Enterprise Crude Oil, LLC (38%); Shell Trading Company (31%); and Plains Marketing, L.P. (15%). At December 31, 2013 our receivables from the sale of our oil and natural gas production were approximately $13.2 million in total.

ITEM 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Callon Petroleum Company

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Callon Petroleum Company as of December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Callon Petroleum Company's internal control over financial reporting 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 (1992 framework) and our report dated March 12, 2014, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 12, 2014

CALLON PETROLEUM COMPANY
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	For the Year Ended December, 31	
	2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents	$3,012	$1,139
Accounts receivable	20,586	15,608
Fair market value of derivatives	60	1,674
Deferred tax asset, current	3,843	—
Other current assets	2,063	1,502
Total current assets	29,564	19,923
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,701,577	1,497,010
Less accumulated depreciation, depletion and amortization	(1,420,612)	(1,296,265)
Net oil and natural gas properties	280,965	200,745
Unevaluated properties excluded from amortization	43,222	68,776
Total oil and natural gas properties	324,187	269,521
Other property and equipment, net	7,255	10,058
Restricted investments	3,806	3,798
Investment in Medusa Spar LLC	—	8,568
Deferred tax asset	57,765	64,383
Other assets, net	1,376	1,922
Total assets	$423,953	$378,173
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$57,637	$36,016
Asset retirement obligations	4,120	2,336
Fair market value of derivatives	1,036	125
Total current liabilities	62,793	38,477
13% Senior Notes:		
Principal outstanding	48,481	96,961
Deferred credit, net of accumulated amortization of $20,814 and $17,800, respectively	5,267	13,707
Total 13% Senior Notes	53,748	110,668
Credit facility	22,000	10,000
Asset retirement obligations	2,612	10,965
Other long-term liabilities	3,706	2,092
Total liabilities	144,859	172,202
Stockholders' equity:		
Preferred Stock, series A cumulative, $.01 par value and $50.00 liquidation preference, 2,500 shares authorized; 1,579 and 0 shares outstanding, respectively	16	—
Common Stock, $.01 par value, 60,000 shares authorized; 40,345 and 39,801 shares outstanding at December 31, 2013 and 2012, respectively	404	398
Capital in excess of par value	401,540	328,116
Retained deficit	(122,866)	(122,543)
Total stockholders' equity	279,094	205,971

Total liabilities and stockholders' equity	$423,953	$378,173

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the Year Ended December 31,		
	2013	2012	2011
Operating revenues:			
Oil sales	$88,960	$96,584	$100,962
Natural gas sales	13,609	14,149	26,682
Total operating revenues	102,569	110,733	127,644
Operating expenses:			
Lease operating expenses	19,779	23,330	18,285
Production taxes	4,133	3,224	2,062
Depreciation, depletion and amortization	43,967	49,701	48,701
General and administrative	20,534	20,358	16,636
Accretion expense	1,785	2,253	2,338
Impairment of other property and equipment	1,707	1,177	—
Total operating expenses	91,905	100,043	88,022
Income from operations	10,664	10,690	39,622
Other (income) expenses:			
Interest expense	6,094	9,108	11,717
Gain on early extinguishment of debt	(3,696)	(1,366)	(1,942)
Gain on acquired equipment	—	—	(5,041)
Loss (gain) on derivative contracts	1,360	(1,717)	—
Other income	(485)	(79)	(1,426)
Total other expenses	3,273	5,946	3,308
Income before income taxes	7,391	4,744	36,314
Income tax expense (benefit)	3,104	2,223	(69,283)
Income before equity in earnings of Medusa Spar LLC	4,287	2,521	105,597
Equity in earnings of Medusa Spar LLC, net of tax	17	226	799
Net income	4,304	2,747	106,396
Preferred stock dividends	(4,627)	—	—
Income (loss) available to common shareholders	$(323)	$2,747	$106,396
Income (loss) per common share:			
Basic	$(0.01)	$0.07	$2.81
Diluted	$(0.01)	$0.07	$2.76
Shares used in computing income per common share:			
Basic	40,133	39,522	37,908
Diluted	40,133	40,337	38,582

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

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CALLON PETROLEUM COMPANY
CONSOLIDATE STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	For the Year Ended December 31,		
	2013	2012	2011
Net income	$4,304	$2,747	$106,396
Other comprehensive income (loss):			
Change in fair value of derivatives designated as hedges, net of tax	—	(1,624)	2,561
Comprehensive income	4,304	1,123	108,957
Preferred stock dividends	(4,627)	—	—
Comprehensive income (loss) available to common shareholders	$(323)	$1,123	$108,957

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

	Preferred Stock	Common Stock	Capital in Excess of Par	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Stockholders' Equity
Balance at 12/31/2010	$—	$290	$248,160	$(937)	$(231,703)	$15,810
Comprehensive income:						
Net income	—	—	—		106,396	
Other comprehensive income				2,561		
Total comprehensive income						108,957
Shares issued pursuant to employee benefit plans	—	—	207	—	—	207
Restricted stock	—	3	2,446	—	—	2,449
Common stock issued	—	101	73,661	—	—	73,762
Reconsolidated subsidiary (See Note 13)	—	—	—	—	17	17
Balance at 12/31/2011	$—	$394	$324,474	$1,624	$(125,290)	$201,202
Comprehensive income:						
Net income	—	—	—		2,747	
Other comprehensive loss				(1,624)		
Total comprehensive income						1,123
Shares issued pursuant to employee benefit plans	—	—	235	—	—	235
Restricted stock	—	4	3,407	—	—	3,411
Balance at 12/31/2012	$—	$398	$328,116	$—	$(122,543)	$205,971
Comprehensive income:						
Net income and comprehensive income	—	—	—	—	4,304	4,304
Shares issued pursuant to employee benefit plans	—	—	243	—	—	243
Restricted stock	—	6	3,162	—	—	3,168
Preferred stock issued	16		70,019			70,035
Preferred stock dividend					(4,627)	(4,627)
Balance at 12/31/2013	$16	$404	$401,540	$—	$(122,866)	$279,094

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Year Ended December 31,		
	2013	2012	2011
Cash flows from operating activities:			
Net income	$4,304	$2,747	$106,396
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	45,393	51,043	49,753
Accretion expense	1,785	2,253	2,338
Amortization of non-cash debt related items	471	402	461
Amortization of deferred credit	(3,164)	(3,086)	(3,155)
Equity in earnings of Medusa Spar LLC	(17)	(226)	(799)
Deferred income tax expense	2,778	2,223	10,928
Valuation allowance	—	—	(80,211)
Net loss (gain) on derivatives, net of settlements	2,730	(1,683)	—
Impairment of other property and equipment	1,707	1,176	—
Gain on acquired equipment	—	—	(4,995)
Non-cash gain for early debt extinguishment	(3,696)	(1,366)	(1,942)
Non-cash expense related to equity share-based awards	2,092	1,697	1,337
Change in the fair value of liability share-based awards	2,903	1,620	761
Payments to settle asset retirement obligations	(721)	(1,314)	(2,563)
Changes in current assets and liabilities:			
Accounts receivable	(3,497)	(883)	(3,734)
Other current assets	(560)	100	180
Current liabilities	3,583	1,753	4,695
Payments to settle vested liability share-based awards	(239)	(3,383)	—
Change in natural gas balancing receivable	22	51	252
Change in natural gas balancing payable	(527)	(102)	(115)
Change in other long-term liabilities	(206)	205	100
Change in other assets, net	(812)	(1,937)	(520)
Net cash provided by operating activities	54,329	51,290	79,167
Cash flows from investing activities:			
Capital expenditures	(159,724)	(133,299)	(100,243)
Acquisitions	(10,885)	(2,075)	—
Proceeds from sale of mineral interests and equipment	89,992	39,936	7,615
Investment in restricted assets related to plugging and abandonment	—	—	(150)
Distribution from Medusa Spar LLC	813	1,735	1,267
Net cash used in investing activities	(79,804)	(93,703)	(91,511)
Cash flows from financing activities:			
Borrowings on credit facility	80,000	53,000	—
Payments on credit facility	(68,000)	(43,000)	—
Redemption of 13% Senior Notes	(50,060)	(10,225)	(35,062)
Issuance of preferred stock	70,035	—	—
Issuance of common stock	—	—	73,765
Payment of preferred stock dividends	(4,627)	—	—
Taxes paid related to exercise of employee stock options	—	(18)	—
Net cash provided by (used in) financing activities	27,348	(243)	38,703
Net change in cash and cash equivalents	1,873	(42,656)	26,359
Cash and cash equivalents:			

Balance, beginning of period	1,139	43,795	17,436
Balance, end of period	$3,012	$1,139	$43,795

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

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NOTE 1 – Description of Business and Basis of Presentation

Callon Petroleum Company is an independent oil and natural gas company established in 1950, which has been focused on building reserves and production both onshore and offshore through efficient operations and low finding and development costs. In 2013, the Company completed the onshore strategic repositioning it initiated in 2009, shifting its operations from the offshore waters in the Gulf of Mexico to the Permian Basin region in Texas. The Company has built seasoned technical and operational teams with extensive experience in the Permian Basin to manage and progress its growth plan. In the fourth quarter of 2012, Callon sold its interest in its deepwater Habanero field. Similarly, in the fourth quarter of 2013, the Company sold its interest in its only remaining deepwater property, the Medusa field, including the sale of the Medusa Spar facility and substantially all remaining offshore shelf properties. These transactions completed the Company's long-term strategic goal of becoming an onshore operator with an asset base concentrated in the Permian Basin.

The Company was incorporated under the laws of the state of Delaware in 1994 and succeeded to the business of a publicly traded limited partnership, a joint venture with a consortium of European investors and an independent energy company partially owned by a member of current management. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

The Consolidated Financial Statements include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company ("CPOC"). CPOC also includes the subsidiaries Callon Offshore Production, Inc. and Mississippi Marketing, Inc. All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to presentation in the current year. To the extent these amounts are material, we have either footnoted them within the Company's disclosures or have noted the items within this footnote. The Company reclassified on its 2012 and 2011 Consolidated Statements of Operations $3,224 and $2,062, respectively, from "Lease operating expenses" to "Production taxes" to conform to current year presentation.

Unless otherwise indicated, all amounts included within the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.

NOTE 2 – Summary of Significant Accounting Policies

A. Use of Estimates

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

B. Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

C. Accounts Receivable

Accounts receivable consists primarily of accrued oil and natural gas production receivables. The balance in the reserve for doubtful accounts netted within accounts receivable was $73 and $34 at December 31, 2013 and 2012, respectively. During 2013, 2012, and 2011 the Company recorded $45, $0 and $(281), respectively of bad debt expense. The negative bad debt expense in 2011 relates to the collection of an amount charged to bad debt expense during 2010.

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Callon Petroleum Company | Notes to the Consolidated Financial Statements (All amounts in thousands, except well, acreage, per-share and per-derivative instrument data) | Table of Contents

D. Revenue Recognition and Natural Gas Balancing

The Company recognizes revenue under the entitlement method of accounting. Under this method, revenue is deferred for deliveries in excess of the Company's net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the lower of cost or market. The revenue we receive from the sale of NGLs is included in natural gas sales. Natural gas balancing receivables were $71 and $93 as of 2013 and 2012, respectively. Natural gas balancing payables were $126 and $653 as of 2013 and 2012, respectively.

E. Major Customers

The Company's production is generally sold on month-to-month contracts at prevailing prices. The following table identifies customers to whom it sold a greater than 10% of its total oil and natural gas production during each of the years ended:

	For the Year Ended December 31,					
	2013		2012		2011	
Enterprise Crude Oil, LLC	38	%	32	%	16	%
Shell Trading Company	31	%	39	%	45	%
Plains Marketing, L.P.	15	%	15	%	17	%
Other	16	%	14	%	22	%
Total	100	%	100	%	100	%

Because alternative purchasers of oil and natural gas are readily available, the Company believes that the loss of any of these purchasers would not result in a material adverse effect on its ability to market future oil and natural gas production.

F. Oil and Natural Gas Properties

The Company uses the full-cost method of accounting for its exploration and development activities. Under this method of accounting, the cost of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, interest capitalized on unevaluated leases, other costs related to exploration and development activities, and site restoration, dismantlement and abandonment costs capitalized in accordance with asset retirement obligation accounting guidance. Costs capitalized also include any internal costs that are directly related to exploration and development activities, including salaries and benefits, but do not include any costs related to production, general corporate overhead or similar activities. The Company capitalized $14,753, $13,331 and $11,857 of these internal costs during 2013, 2012 and 2011, respectively.

When applicable, proceeds from the sale or disposition of oil and natural gas properties are accounted for as a reduction to capitalized costs unless the sale would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized in income.

Costs of oil and natural gas properties, including future development costs, which have proved reserves and properties which have been determined to be worthless, are depleted using the unit-of-production method based on proved reserves. Excluded from this amortization are costs associated with unevaluated properties, including capitalized interest on such costs. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties or management determines that these costs have been impaired.

Under the full-cost accounting rules of the SEC, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full-cost ceiling amount). These rules generally require pricing based on the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the "ceiling" is exceeded. See Note 12 for additional information regarding the Company's oil and natural gas properties.

Upon the acquisition or discovery of oil and natural gas properties, the Company estimates the future net costs to dismantle, abandon and restore the property by using available geological, engineering and regulatory data. Such cost estimates are periodically updated for changes in conditions and requirements. In accordance with asset retirement obligation guidance issued by the FASB, such costs are capitalized to the full-cost pool when the related liabilities are incurred. In accordance with SEC's rules, assets recorded in connection with the recognition of an asset retirement obligation are included as part of the costs subject to the full-cost ceiling limitation. The future cash outflows associated with settling the recorded asset retirement obligations are excluded from the computation of the present value of estimated future net revenues used in determining the full-cost ceiling amount.

G. Other Property and Equipment

The Company depreciates its other property and equipment of $7,255 and $6,424 at December 31, 2013 and 2012, respectively, using the straight-line method over estimated useful lives of three to 20 years. Depreciation expense of $750, $760 and $645 relating to other property and equipment was included in general and administrative expenses in the Company's consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011, respectively. The accumulated depreciation on other property and equipment was $13,240 and $13,238 as of December 31, 2013 and 2012, respectively. As discussed in Note 13, during 2013, the Company recorded an impairment charge to reduce to zero the carrying values of its assets held for sale. The Company reviews its other property and equipment for impairment when indicators of impairment exist.

H. Capitalized Interest

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization (e.g. unevaluated properties). Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. Capitalized interest cannot exceed gross interest expense. During the years ended December 31, 2013, 2012 and 2011, the Company capitalized $4,410, $2,109 and $573 of interest expense.

I. Asset Retirement Obligations

The Company is required to record its estimate of the fair value of liabilities for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligations and reported as accretion expense within operating expenses in the consolidated statements of operations. See Note 11 for additional information.

J. Derivatives

The Company's derivative contracts executed prior to 2012 were designated as cash flow hedges, and were recorded at fair market value with the changes in fair value recorded net of tax through other comprehensive income (loss) ("OCI") in stockholders' equity. Ineffective derivative contracts or ineffective portions of contracts designated as cash flow hedges were recognized as derivative expense (income). The last of the Company's derivative contracts designated as cash flow hedges expired on December 31, 2012. Derivative contracts executed during 2013 and outstanding as of December 31, 2013 were not designated as accounting hedges, and are carried on the balance sheet at their fair market value. Changes in the fair value of derivative contracts not designated as accounting hedges are reflected in earnings as a gain or loss on derivative contracts. See Notes 5 and 6 for additional information regarding the Company's derivative contracts.

K. Income Taxes

Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and natural gas properties for financial reporting purposes and income tax purposes. GAAP requires the recognition of a deferred tax asset for net operating loss carryforwards, statutory depletion carryforward and tax credit carryforwards, net of a valuation allowance. A valuation allowance is provided for that portion, if any, of the asset for which it is deemed more likely than not that it will not be realized. See Note 10 for additional information.

L. Share-Based Compensation

The Company grants to directors and employees stock options, restricted stock awards (“RS awards”), and restricted stock unit awards (“RSU awards”) that may be settled in cash or common stock at the option of the Company and RSU awards that may only be settled in cash (“Cash-settleable RSU awards”).

Stock Options. For stock options the Company expects to settle in common stock, share-based compensation expense is based on the grant-date fair value as calculated using the Black-Scholes option pricing model and recognized straight-line over the vesting period (generally three years).

RS awards, RSU awards and Cash-settleable RSU awards. For RS and RSU awards that the Company expects to settle in common stock, share-based compensation expense is based on the grant-date fair value and recognized straight-line over the vesting period (generally three years). For Cash-settleable RSU awards that the Company expects or is required to settle in cash, share-based compensation expense is based on the fair value remeasured at each reporting period as calculated using a Monte Carlo pricing model, because vesting of these awards is subject to a market condition, with the estimated value recognized over the vesting period (generally three years).

M. Statements of Cash Flows Supplemental Information

During the three year period ended 2013, the Company paid no federal income taxes. During the years ended December 31, 2013, 2012 and 2011, the company made cash interest payments of $13,189, $13,920 and $14,922, respectively.

N. Investment in Medusa Spar LLC

During the fourth quarter of 2013, the Company closed on the sale of its 15.0% working interest in the Medusa field, its 10.0% membership interest in Medusa Spar LLC (“LLC”), and substantially all of its remaining Gulf of Mexico shelf properties. Prior to the sale, the Company’s ownership interest in the LLC was accounted for under the equity method of accounting for investments. The LLC held a 75% undivided ownership interest in the deepwater spar production facilities at the Medusa field in the Gulf of Mexico and earned a tariff based upon production volume throughput from the Medusa area. The Company was obligated to process through the spar production facilities its share of production from the Medusa field and any future discoveries in the area. The balance of the LLC was owned by Oceaneering International, Inc. and Murphy Oil Corporation. See Note 12 for additional information on the Medusa divestiture.

O. Consolidation of Variable Interest Entities

In June 2009, the FASB issued an accounting standard which became effective for and was adopted by the Company on January 1, 2010. Upon adoption, the Company reevaluated its interest in its subsidiary, Callon Entrada. Based on the evaluation performed, management concluded that a VIE reconsideration event had taken place resulting in the determination that Callon Entrada is a VIE, for which the Company is not the primary beneficiary. Therefore, effective January 1, 2010, Callon Entrada was deconsolidated from the consolidated financial statements of the Company. During the second quarter of 2011 and through the formal execution of a wind-down agreement with its former joint interest partner in the Entrada deepwater project, which resulted in Callon gaining the power to direct the activities of Callon Entrada, the Company became the primary beneficiary of Callon Entrada. Consequently, effective April 29, 2011, Callon Entrada was reconsolidated in the Company’s financial statements. Callon Entrada was later dissolved in 2011.

P. Earnings per Share (EPS)

The Company’s basic EPS amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted EPS, using the treasury-stock method, reflects the potential dilution caused by the exercise of all options and vesting of all restricted stock and restricted stock units settleable in shares.

Q. Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by FASB that are adopted by the Company as of the specified effective date. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on the Company's financial statements upon adoption.

In February 2013, the Financial Accounting Standards Board issued an Accounting Standards Update (ASU) that clarified the reclassification requirements from accumulated other comprehensive income to net income and required disclosure of amounts reclassified out of accumulated other comprehensive income by component. In addition, it requires that the Company present either on the face of its financial statements or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount is reclassified in its entirety to net income in the same reporting period. For amounts not reclassified in their entirety to net income, the Company is required to cross-reference to the related note on the face of the financial statements for additional information. Callon adopted this guidance effective January 1, 2013, which did not have a material impact on its financial statements.

NOTE 3 - Earnings (loss) per Share

Basic earnings (loss) per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings (loss) per share includes the potential dilutive impact of non-vested restricted shares and unexercised options outstanding during the periods presented, as calculated using the treasury stock method, unless their effect is anti-dilutive. A reconciliation of the basic and diluted net income per share computation is as follows (in thousands, except per share amounts):

	For the year ended December 31,		
	2013	2012	2011
Net income	$4,304	$2,747	$106,396
Preferred stock dividends	(4,627)	—	—
(a) Income (loss) available to common shareholders	$(323)	$2,747	$106,396
(b) Weighted average shares outstanding	40,133	39,522	37,908
Dilutive impact of stock options	—	8	18
Dilutive impact of restricted stock	—	807	656
(c) Weighted average shares outstanding for diluted net income (loss) per share (1)	40,133	40,337	38,582
Basic Income (loss) per share (a/b)	$(0.01)	$0.07	$2.81
Diluted Income (loss) per share (a/c)	$(0.01)	$0.07	$2.76
The following were excluded from the diluted EPS calculations because their effect would be anti-dilutive:			
Stock options	52	52	67
Restricted stock	398	123	816

(1) Because the Company reported a loss for the year ended December 31, 2013, no unvested stock awards were included in computing loss per share because the effect was anti-dilutive.

NOTE 4 - Borrowings

	For the year ended December 31,	
	2013	2012
Principal components:		
Credit Facility	$22,000	$10,000
13% Senior Notes due 2016, principal	48,481	96,961
Total principal outstanding	$70,481	$106,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	5,267	13,707
Total carrying value of borrowings	$75,748	$120,668

Senior Secured Revolving Credit Facility (the “Credit Facility”)

The Company’s $200,000 Credit Facility, for which Regions Bank serves as the Administrative Agent, matures March 15, 2016 and includes Citibank, NA, IberiaBank, Whitney Bank and OneWest Bank, FSB as participating lenders. The Company’s Credit Facility had an approved borrowing base at December 31, 2013 of $83,000. The Credit Facility was secured by mortgages covering the Company’s major producing fields. As of December 31, 2013, the balance outstanding on the Credit Facility was $22,000 with an interest rate of 2.92%, calculated as the London Interbank Offered Rate (LIBOR), plus a tiered rate ranging from 2.5% to 3.0%, which is determined by utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly.

Subsequent to December 31, 2013, the Company amended its existing Credit Facility as discussed below. Additionally, the Company executed the Second Lien Facility also discussed below.

Amended Credit Facility ("the Amended Credit Facility")

On March 11, 2014, the Company entered into the Fifth Amended and Restated Credit Agreement million with JPMorgan Chase Bank, National Association as Administrative Agent.

The Amended Credit Facility includes the following key provisions:

- $500,000 notional amount, with an initial borrowing base of $95,000;
- Maturity date of March 11, 2019;
- First redetermination scheduled with an effective date of May 30, 2014, with subsequent redeterminations occurring every six months beginning on September 1, 2014;
- Pricing grid providing from Eurodollar-based draws ranging from LIBOR plus 1.75% to 2.75% depending on utilization;
- A quarterly commitment fee equal to 0.5% per year of the unused portion of the borrowing base; and
- Secured by mortgages covering all major producing fields.

The Amended Credit Facility contains various affirmative and restrictive covenants.

Second Lien Term Loan Facility (the "Second Lien Facility")

In conjunction with the Amended Credit Facility, the Company entered into the Second Lien Facility in an aggregate amount of up to $125,000 with JPMorgan Chase Bank, National Association as Administrative Agent. The Second Lien Facility is structured as a multiple advance term loan facility, with initial commitments of $100,000. If any portion of the committed Second Lien Facility remains undrawn on the first anniversary of the closing date, then the unfunded commitments under the Second Lien Facility, if any, will terminate on such date.

The Second Lien Facility includes the following key provisions:

- $125,000 master note, with initial commitments $100,000 and additional availability of $25,000 with consent of 66 2/3% of the lenders and compliance with financial covenants after giving effect to such increase;
- Maturity date of September 11, 2019;
- No mandatory prepayments unless new debt is issued;
- Prepayable at any time. The prepayment premium shall be applicable to the amount of the applicable prepayment multiplied by (i) 102% if such prepayment event occurs prior to the first anniversary of the Closing Date and (ii) 101% if such prepayment event occurs on or after the first but prior to the second anniversary of the Closing Date. No such prepayment premium shall be payable for prepayments made on or after the second anniversary of the closing date;
- Interest expense at a rate of LIBOR plus 7.75%, calculated on a per annum basis;
- A commitment fee equal to 0.5% calculated on a per annum basis on the unused portion of the initial commitment amount until March 11, 2015;
- The amounts funded on the initial draw date shall be issued with an original issue discount of 1.00% and each subsequent draw shall be subject to the same 1.00% original issue discount on the drawn amount, applied on the date such draw is funded; and
- Secured by junior liens on properties mortgaged under the Amended Credit Facility, subject to an intercreditor agreement.

The Second Lien Facility contains various affirmative and restrictive covenants.

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13% Senior Notes due 2016 (the "Senior Notes") and Deferred Credit

As of December 31, 2013, the Company had principal outstanding of $48,481 related to its 13% Senior Notes. The interest coupon is payable on the last day of each quarter. Certain of the Company's subsidiaries guarantee the Company's obligations under the unsecured Senior Notes. The subsidiary guarantors are 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations, and any subsidiaries of the parent company other than the subsidiary guarantors are minor. Upon issuing the Senior Notes in November 2009, the Company reduced the carrying amount of the Old Notes by the fair value of the common and preferred stock issued in the amount of $11,527. The $31,507 difference between the adjusted carrying amount of the Old Notes and the face value of the Senior Notes was recorded as a deferred credit, which is being amortized as a reduction in interest expense over the life of the Senior Notes at an 8.5% effective interest rate. The following table summarizes the Company's deferred credit balance at December 31, 2013:

Gross Carrying Amount	Accumulated Amortization at December 31, 2013	Carrying Value at December 31, 2013	Amortization Recorded during Current Year (a)	Estimated Annual Amortization Expense Expected to be Recognized in 2014
$31,507	$26,240	$5,267	$8,440	$5,267

(a) Of the amount recorded as amortization during the current year, $3,165 was recorded as a reduction of interest expense and $5,275 (discussed below) was recorded as a component of the gain on early extinguishment of debt.

Using a portion of the proceeds from the sale of our interest in Medusa on December 17, 2013, the Company redeemed $48,481 of its Senior Notes, which resulted in a net $3,696 gain on the early extinguishment of debt. The gain represents the difference between the $50,057 paid (inclusive of $1,576 of redemption expenses, primarily the call premium) for Senior Notes with a carrying value of $53,756 (inclusive of the $5,275 of accelerated deferred credit amortization).

In June 2012, the Company redeemed $10,000 of its Senior Notes, which resulted in a net $1,366 gain on the early extinguishment of debt. The gain represents the difference between the $10,225 paid (inclusive of $225 of redemption expenses, primarily the call premium) for Senior Notes with a carrying value of $11,591 (inclusive of the $1,591 of accelerated deferred credit amortization).

In March 2011, the Company redeemed $31,000 of its Senior Notes using proceeds from its February 2011 equity offering, which resulted in a $1,974 gain on the early extinguishment of debt. The gain represents the difference between the $35,062 paid (inclusive of the$4,062 of redemption expenses, primarily the call premium) for Senior Notes with a carrying value of $37,004 (inclusive of the $6,004 of accelerated deferred credit amortization).

On March 11, the Company provided notice to holders of its outstanding Senior Notes that it expects to redeem those notes on April 11, 2014 using proceeds from the previously discussed Second Lien Facility. The redemption will result in the acceleration of the amortization of the remaining $5,267 of deferred credit as reflected in the table above.

Restrictive Covenants

The Indenture governing our Senior Notes and the Company's Credit Facility contains various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, Callon's Credit Facility contains covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at December 31, 2013.

NOTE 5 – Derivative Instruments and Hedging Activities

Objectives and Strategies for Using Derivative Instruments

The Company is exposed to fluctuations in oil and natural gas prices on the majority of its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its oil and natural gas production. The Company utilizes primarily a mix of collar, swap, put and call derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative or trading purposes.

Counterparty risk and offsetting

The use of derivative transactions exposes the Company to the risk that a counterparty will be unable to meet its commitments. While the Company monitors counterparty creditworthiness on an ongoing basis, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices. Counterparty credit risk is considered when determining a derivative instruments' fair value; See Note 6 for additional information regarding fair value.

The Company executes commodity derivative transactions under master agreements that have netting provisions that provide for offsetting payables against receivables. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a cash payment transfer or terminate the arrangement.

Financial statement presentation and settlements

Settlements of the Company's derivative instruments are based on the difference between the contract price or prices specified in the derivative instrument and a New York Mercantile Exchange ("NYMEX") price. The fair value of the Company's derivative instruments, depending on the type of instruments, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. See Note 6 for additional information regarding fair value.

Beginning in 2012, the Company elected not to designate its executed derivative contracts, nor does it expect to designate future derivative contracts, as an accounting hedge under FASB ASC 815. Consequently, any derivative contract not designated as an accounting hedge will be carried at its fair value on the balance sheet and marked-to-market at the end of each period, with the change in value reflected as a gain or loss on the statement of operations. Gains and losses on derivatives that are not designated as hedges are recorded in earnings as a component of gain (loss) on derivative contracts. Within the gain (loss) on derivative contracts line of the statement of operations are gains (losses) on derivatives, net of settlement and gains (losses) on derivatives, settled.

Prior to 2012, the Company's derivative contracts recorded on the Consolidated Balance Sheets were designated as cash flow hedges, and were recorded at fair market value with the changes in fair value recorded net of tax through OCI in stockholders' equity. The cash settlements on effective derivative contracts were recorded as an increase or decrease in oil and natural gas sales.

The following table reflects the fair values of the Company's derivative instruments for the periods presented (none of which were designated as hedging instruments under ASC 815):

	Balance Sheet Presentation		Asset Fair Value		Liability Fair Value		Net Derivative Fair Value	
Commodity	Classification	Line Description	12/31/13	12/31/12	12/31/13	12/31/12	12/31/13	12/31/12
Derivatives not designated as Hedging Instruments under ASC 815								
Natural gas	Current	Fair market value of derivatives	$60	$—	$—	$(125)	$60	$(125)
Natural gas	Non-current	Other long-term liabilities	—	—	(72)	(116)	(72)	(116)
Oil	Current	Fair market value of derivatives	—	1,674	(1,036)	—	(1,036)	1,674
Oil	Non-current	Other long-term assets	—	250	—	—	—	250
	Totals		$60	$1,924	$(1,108)	$(241)	$(1,048)	$1,683

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The Company’s derivative contracts are subject to netting arrangements and, being representative of the way in which the contracts settle, are presented in the balance sheet at their fair values on a net basis based on the underlying commodity being hedged. The following presents the impact of this presentation to the Company’s recognized assets and liabilities at December 31, 2013:

	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of hedging contracts	$8	$52	$60
Long-term assets: Fair value of hedging contracts	—	—	—
Current liabilities: Fair value of hedging contracts	1,088	(52)	1,036
Long-term liabilities: Fair value of hedging contracts	(72)	—	(72)

Derivatives not designated as hedging instruments under ASC 815

For the periods indicated, the Company recorded the following related to its derivative instruments that were not designated as accounting hedges and are recorded in the Statement of Operations as gain or loss on derivative contracts:

	For the year ended December 31,		
	2013	2012	2011
Natural gas derivatives			
Net (loss) gain on derivatives, settled	$(147)	$34	$—
Net gain (loss) on derivatives, net of settlements	229	(241)	—
Subtotal gain (loss), net	$82	$(207)	$—
Oil derivatives			
Net gain, on derivatives, settled	$1,518	$—	$—
Net (loss) gain on derivatives, net of settlements	(2,960)	1,924	—
Subtotal (loss) gain, net	$(1,442)	$1,924	$—
Total (loss) gain on derivative instruments included in Statement of Operations	$(1,360)	$1,717	$—

Derivatives designated as hedging instruments under ASC 815

The table below presents the effect of the Company’s derivative financial instruments on the consolidated statements of operations as an increase (decrease) to oil and natural gas sales for the effective portion and as an increase (decrease) to other (income) expense for the ineffective portion and amounts excluded from effectiveness testing:

	For the year ended December 31,		
	2013	2012	2011
Amount of gain (loss) reclassified from OCI into income (effective portion)	$—	$1,420	$(375)
Amount of gain (loss) recognized in income (ineffective portion and amount excluded from effectiveness testing)	—	—	—

(All amounts in thousands, except well, acreage, per-share and per-derivative instrument data)

Derivative positions
In the first quarter of 2013, the Company monetized the remaining portion of its 2013 oil collar positions (for the period February - December 2013) of 40 Bbls per month. The proceeds from this transaction, combined with the proceeds from the sale of the below listed put for 30 Bbls per month, were used to finance the uplift in the oil swap for the period February - December 2013.

Listed in the table below are the outstanding oil and natural gas derivative contracts as of December 31, 2013:

Commodity	Instrument	Average Notional Volumes per Month	Quantity Type	Put/Call Price	Fixed-Price Swap	Period	Designation under ASC 815	
Natural gas	Call Option	38	MMBtu	$4.75	n/a	Jan14 - Mar14	Not Designated	
Natural gas	Swap	60	MMBtu	n/a	$4.36	Jan14 - Mar14	Not Designated	
Natural gas	Call Option	38	MMBtu	$4.75	n/a	Jan14 - Dec14	Not Designated	(a)
Oil	Swap	30	Bbls	n/a	$93.35	Jan14 - Dec14	Not Designated	
Oil	Put Option	30	Bbls	$70.00	n/a	Jan14 - Dec14	Not Designated	
Oil	Swap	9	Bbls	n/a	$94.58	Jan14 - Dec14	Not Designated	
Natural gas	Swap	46	MMBtu	n/a	$4.25	Apr14 - Dec14	Not Designated	
Natural gas	Call Option	38	MMBtu	$4.75	n/a	Apr14 - Dec14	Not Designated	
Natural gas	Call Option	37	MMBtu	$5.00	n/a	Jan15 - Dec15	Not Designated	

(a) The short natural gas call option, when combined with the Company's long production position, represents a "covered call," and creates a $4.75/MMbtu ceiling during the covered period.

Subsequent Event Activity:

Derivative contracts executed subsequent to December 31, 2013 include the following:

Commodity	Instrument	Average Notional Volumes per Month	Quantity Type	Put/Call Price	Fixed-Price Swap	Period	Designation under ASC 815
Oil	Swap	15	Bbls	n/a	$94.15	Feb14 - Mar14	Not Designated
Oil	Swap	15	Bbls	n/a	$92.80	Apr14 - Jun14	Not Designated
Oil	Swap	15	Bbls	n/a	$90.40	Jul14 - Sep14	Not Designated
Oil	Swap	15	Bbls	n/a	$88.64	Oct14 - Dec14	Not Designated

NOTE 6 – Fair Value Measurements

Fair value is defined within the accounting rules as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The rules established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

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

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Fair Value of Financial Instruments

Cash, Cash Equivalents, and Short-Term Investments. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The Company's debt is recorded at the carrying amount on its Consolidated Balance Sheet. The fair value of Callon's fixed-rate debt, which is valued using Level 2 inputs, is based upon estimates provided by an independent investment banking firm. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

The following table summarizes the respective carrying and fair values at:

	For the year ended December 31,			
	2013		2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$22,000	$22,000	$10,000	$10,000
13% Senior Notes due 2016 (a)	53,748	50,299	110,668	100,112
Total	$75,748	$72,299	$120,668	$110,112

(a) 2013 and 2012 fair values are calculated only in relation to the $48,481 and $96,961 face value outstanding of the 13% Senior Notes, respectively. The remaining $5,267 and $13,707, respectively represents the Company's deferred credits and have been excluded from the fair value calculation. See Note 4 for additional information.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis (unless otherwise noted below) in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Commodity Derivative Instruments. The fair value of commodity derivative instruments is derived using a valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract, and the values are corroborated by quotes obtained from counterparties to the agreements. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. The Company believes that the majority of the inputs used to calculate the commodity derivative instruments fall within Level 2 of the fair-value hierarchy based on the wide availability of quoted market prices for similar commodity derivative contracts. See Note 5 for additional information regarding the Company's derivative instruments.

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis for each hierarchy level:

December 31, 2013	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current Portion	Fair market value of derivatives	$—	$60	$—	$60
Derivative financial instruments - non-current	Other assets, net	—	—	—	—
Sub-total assets		$—	$60	$—	$60

Liabilities					
Derivative financial instruments - current portion	Fair market value of derivatives	$—	$1,036	$—	$1,036
Derivative financial instruments - non-current	Other long-term liabilities	—	72	—	72
Sub-total liabilities		$—	$1,108	$—	$1,108
Total		$—	$(1,048)	$—	$(1,048)

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December 31, 2012	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current portion	Fair market value of derivatives	$—	$1,674	$—	$1,674
Derivative financial instruments - non-current	Other assets, net	—	250	—	250
Sub-total assets		$—	$1,924	$—	$1,924
Liabilities					
Derivative financial instruments - current portion	Fair market value of derivatives	$—	$125	$—	$125
Derivative financial instruments - non-current	Other long-term liabilities	—	116	—	116
Sub-total liabilities		$—	$241	$—	$241
Total		$—	$1,683	$—	$1,683

The derivative fair values above are based on analysis of each contract. Derivative assets and liabilities with the same counterparty are presented here on a gross basis, even where the legal right of offset exists. See Note 5 for a discussion of net amounts recorded in the Consolidated Balance Sheet at December 31, 2013.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Other Property and Equipment. As discussed in Note 13, the Company's decision to abandon certain of its other property and equipment, that had been classified as held for sale, resulted in an impairment charge of $1,707 which is included in the Company's Statement of Operations for the year ended December 31, 2013. The impairment charge was valued using level 3 inputs.

Acquisition. During the second quarter of 2013, the Company acquired approximately 2,468 gross (2,186 net) acres in Reagan and Upton Counties, Texas, which is located in the southern portion of the Midland Basin for a purchase price of $11,000. The acquisition also included seven gross vertical wells and 1,301 barrels of oil equivalent proved reserves. The Company valued the acquired assets in accordance with the method described below. In accordance with the acquisition method of accounting, the purchase price of the Company's acquisition during the period has been allocated to the assets acquired and liabilities assumed based on their estimated fair values on the acquisition date. In valuing the acquired assets and liabilities assumed, fair values were based on expected future cash flows based on estimated reserve quantities; costs to produce and develop reserves; and oil and gas forward prices. The purchase price of the Company's acquisition during the period was $11,000 with approximately $2,000 allocated to unevaluated oil and gas properties and approximately $9,000 allocated to evaluated oil and gas properties. Asset retirement obligations assumed in connection with the transaction were insignificant due to the nature of the properties acquired. The unaudited pro forma results of the properties acquired are immaterial to the Company's financial statements. The fair value measurements were based on significant inputs not observable in the market and thus represent a level 3 measurement.

NOTE 7 – Employee Benefit Plans

The Company utilizes various forms of incentive compensation designed to align the interest of the executives and employees with those of its stockholders. Tabular disclosures related to the share-based awards are presented in Note 8. The narrative that follows provides a brief description of each plan, summarizes the overall status of each plan and discusses current year awards under each plan:

Savings and Protection Plan

The Savings and Protection Plan ("401-K Plan") provides employees with the option to defer receipt of a portion of their compensation, and the Company may, at its discretion, match a portion of the employee's deferral with cash. The Company may also elect, at its discretion, to contribute a non-matching amount in cash and Company Common Stock to employees. The amounts held under the 401-K Plan are invested in various funds maintained by a third party in accordance with the directions of each employee. An employee is fully vested, including Company discretionary contributions, immediately upon participation in the 401-K Plan. The total amounts contributed by the Company, including the value of the common stock contributed, were $923, $918 and $811 in the years 2013, 2012 and 2011, respectively.

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2011 Omnibus Incentive Plan (the "2011 Plan")

The 2011 Plan, which became effective May 12, 2011 following shareholder approval, authorized and reserved for issuance 2,300 shares of common stock, which may be issued upon exercise of vested stock options and/or the vesting of any other share-based equity award that is granted under this plan. The 2011 Plan is the Company's only active plan, and included a provision at inception whereby all remaining, un-issued and authorized shares from the Company's previous share-based incentive plans became issuable under the 2011 Plan. This transfer provision resulted in the transfer of an additional 841 shares into the plan, increasing the quantity authorized and reserved for issuance under the Plan to 3,141 at the inception of the plan. Another provision provided that shares which would otherwise become available for issue under the previous plans as a result of vesting and/or forfeiture of any equity awards existing as of May 12, 2012, would also increase the authorized shares available to the 2011 Plan. As of December 31, 2013, the 2011 Plan had 1,192 shares remaining and eligible for future issuance.

Equity awards issued under this plan may be subject to various vesting, accelerated vesting, and forfeiture provisions upon the occurrence of certain events. Any vested but unexercised options contractually expire 10 years from the date of grant. Equity awards under the 2011 Plan generally vest over time but may also be subject to attaining a specified performance metrics and may be immediate or cliff vest at a specified date. The Company will recognize expense on the grant date for all immediately vesting awards, while it will recognize expense ratably over the requisite service (i.e. vesting) period for both cliff and ratably vesting awards. For performance-based awards, the Company recognizes expense based on its analysis of the performance criteria, and records or reverses expense as necessary based on its analysis. For market-based awards, the Company recognizes expense based on its analysis of the market criteria, and records expense as necessary based on its analysis. Awards with a market-based provision do not allow for the reversal of previously recognized expense, even if the market metric is not achieved and no shares ultimately vest or are awarded.

Cash-Settleable RSU Awards

Certain of the Company's RSUs awarded require cash-settlement. Cash-settleable RSU awards are accounted for as liabilities as the Company is contractually obligated to settle these awards in cash, and are recorded in the Company's consolidated balance sheet for the ratable portion of their fair values. The fair value of the Company's market-based RSU is calculated using a Monte Carlo valuation model, which considers such inputs as the Company's and its peer group's stock prices, a risk-free interest rate, and an estimated volatility for the Company and its peer group. Changes in the fair value of cash-settleable awards are recorded as adjustments to compensation expense.

Market-based RSUs: A significant portion of the Company's cash-settleable RSU awards include a market-based vesting condition and may ultimately vest at a quantity different than the base RSUs awarded. The number of RSUs that cliff-vest is based on a calculation that compares the Company's total shareholder return to the same calculated return of a group of peer companies as selected by the Company, and the number of units that will vest can range between 0% and 200% of the base units awarded.

As of December 31, 2013, the Company had the following cash-settleable RSU awards outstanding (including those that are not based on a market condition):

	Base Units Outstanding at	Potential Minimum Units at Vesting at	Potential Maximum Units at Vesting at
Vesting in 2014	510	45	975

Vesting in 2015	909	60	1,758
Vesting in 2016	66	66	66
Other	92	92	92
Total cash-settleable RSU awards	1,577	263	2,891

For the year ended December 31, 2013, 260 market-based cash-settleable RSUs subject to the peer market-based vesting described above vested at 100% of their issued units, resulting in a cash payment of $1,669. Also during 2013, 65 non-market-based cash settleable RSUs vested, resulting in a cash payment of $239. During 2012, 364 market-based cash-settleable RSUs vested at 150%, resulting in a cash payment of $2,626. Also during 2012, 143 non-market-based cash settleable RSUs vested, resulting in a cash payment of $763. See Note 8 for additional information regarding cash-settleable RSUs.

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NOTE 8 - Share-Based Compensation

As discussed in Note 7, the Company grants various forms of share-based compensation awards to employees of the Company and its subsidiaries and to non-employee members of the Board of Directors. At December 31, 2013, shares available for future share-based awards, including stock options or restricted stock grants, under the Company's only active plan, the 2011 Plan, were 1,192.

The following table presents share-based compensation expense for each respective period:

	For the year ended December 31,					
	2013		2012		2011	
Share-based compensation expense for:	Equity-based	Liability-based	Equity-based	Liability-based	Equity-based	Liability-based
Options	$—	$ —	$—	$ —	$24	$ —
RSU equity awards	3,975	—	4,210	—	2,832	—
Cash-settleable RSU awards	—	5,347	—	2,916	—	1,335
401(k) contributions in shares	219	—	218	—	202	—
Total share-based compensation expense (a)	$4,194	$ 5,347	$4,428	$ 2,916	$3,058	$ 1,335

(a) The portion of this share-based compensation expense that was included in general and administrative expense totaled $5,751, $4,081 and $2,502 for the same years respectively, and the portion capitalized to oil and gas properties was $3,791, $3,263 and $1,891, respectively.

The following table presents the specified share-based compensation expense for the indicated periods:

	For the year ended December 31,		
Unrecognized compensation costs related to:	2013	2012	2011
Unvested RSU equity awards	5,331	6,320	5,748
Unvested cash-settleable RSU awards	7,669	2,826	2,498

The Company's future expected share-based compensation cost related to unvested RSU and cash-settleable RSU awards is expected to be recognized over a weighted-average period of 1.4 years.

The following table summarizes the Company's cash-settleable RSU awards for the periods indicated:

Consolidated Balance Sheets Classification	2013	2012	2011
Accounts payable and accrued liabilities - current portion	$4,173	$1,429	$604
Other long-term liabilities - non-current portion	3,409	1,017	2,309
Total cash-settleable RSU awards	$7,582	$2,446	$2,913

Stock Options

The Company issued no stock options for the past three years and had no options vest or forfeit during 2013. Additionally, no options were exercised, 15 options expired unexercised during the year. As of December 31, 2013, the Company had 52 options outstanding and exercisable at a weighted average exercise price per option of $13.75, with no aggregate intrinsic value and with a weighted-average remaining contract life per unit of 2.3 years.

As of December 31, 2012, the Company had 67 options outstanding and exercisable at a weighted average exercise price per option of $11.82, with no aggregate intrinsic value and with a weighted-average remaining contract life per unit of 2.7 years. The Company net-share settles option exercises and therefore receives no cash proceeds from the exercise of stock options.

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Restricted Stock Units

The following table represents unvested restricted stock activity for the year ended December 31, 2013:

	Number of Shares	Weighted average Grant-Date Fair Value per Share	Period over which expense is expected to be recognized
Outstanding at the beginning of the period	2,295	$5.58	
Granted	944	3.82	
Vested (a)	(754)	5.10	
Forfeited	(223)	5.37	
Outstanding at the end of the period	2,262	$5.03	1.5

a. The fair value of shares vested was $2,689.

NOTE 9 – Equity Transactions

On May 30, 2013, the Company issued 78,947 of 10.0% Series A Cumulative Preferred Stock (the “Preferred Stock”) and received $70,035 net proceeds after deducting the underwriting commissions and offering expenses. The sale consisted of 1,579 shares of Preferred Stock, par value $0.01 per share, public offering price of $47.50 per share and liquidation preference of $50.00 per share in an underwritten public offering. The Preferred Stock ranks senior to the Company’s common stock with respect to the payment of dividends and distribution of assets upon liquidation or dissolution. The Preferred Stock has no stated maturity and is not subject to mandatory redemption or any sinking fund. The Preferred Stock will remain outstanding indefinitely unless repurchased by the Company or converted into Callon common stock in connection with certain changes in control as defined in the Preferred Stock prospectus.

Holders of the Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors (the “Board”), out of funds legally available for the payment of dividends, cumulative cash dividends at a rate of 10.0% per annum of the $50.00 liquidation preference per share (equivalent to $5.00 per annum per share). Dividends are payable quarterly in arrears on the last day of each March, June, September and December when, as and if declared by our Board. The first dividend date for the Preferred Stock was June 30, 2013, and these dividends were paid on June 28, 2013 (as June 30 fell on a weekend) in the amount of $0.43 per share or $679 for the stub period beginning with the issuance on May 30, 2013 through the dividend date on June 30, 2013. For the subsequent quarters ended September 30 and December 31, 2013, the Board of Directors declared for each quarter a dividend of $1.25 per share, or a total of $1,974, on the Company’s Preferred Stock, resulting in total dividend expense recognized in 2013 of $4,627.

Beginning on May 30, 2018, the Company may, solely at its option, redeem the Preferred Stock in whole at any time, or in part from time to time, for cash at a redemption price of $50.00 per share, plus accrued and unpaid dividends (whether or not declared) to the redemption date. The Company may redeem the Preferred Stock following certain changes of control as defined in the Preferred Stock prospectus, in whole or in part, within 120 days after the date on which the change of control has occurred, for cash at $50.00 per share, plus accrued and unpaid dividends (whether or not declared) to the redemption date. If the Company elects not to exercise this option, the holders of the Preferred Stock have the option to convert each share of Preferred Stock into a predefined number of Company common shares, subject to certain adjustments.

As defined in a provision of the Preferred Stock prospectus, the common shares reserved for issuance vary based on the number of authorized common shares. Based on the Company’s 60,000 authorized shares at December 31, 2013, 16,800 shares were reserved for a potential conversion. Subsequent to December 31, 2013, via a majority shareholder vote, the number of authorized shares of common stock was increased from 60,000 to 110,000 with a corresponding increase in the number of common shares reserved for a potential conversion to a maximum of 42,200 shares. Based on the Company's closing common stock price of $6.53 per share on December 31, 2013, the Company reserved 12,090 shares to satisfy the potential conversion.

Except as required by law, holders of the Preferred Stock will have no voting rights unless dividends fall into arrears for six or more quarterly periods (whether or not consecutive). In that event and until such dividends in arrears are paid in full, the holders will be entitled to elect two directors to the Board, which will increase in size by that same number of directors.

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During February, 2011, the Company received $73,765 in net proceeds from the public offering of 10.1 million shares of its common stock, which included the issuance of 1.1 million shares pursuant to the underwriters' over-allotment option. The Company used $35,062 of the proceeds to repurchase $31,000 principal amount of its Senior Notes, with the remaining proceeds intended for general corporate purposes including the planned development of the Company's Permian basin and other onshore assets.

NOTE 10 – Income Taxes

The following table presents Callon's net tax benefits relating to its reported net losses and other temporary differences from operations:

	For the Year Ended December 31	
	2013	2012
Deferred tax asset		
Federal net operating loss carryforward	$70,365	$87,774
Statutory depletion carryforward	8,880	8,184
Alternative minimum tax credit carryforward	208	208
Asset retirement obligations	1,024	3,357
Other	7,575	9,571
Total deferred tax asset	88,052	109,094
Deferred tax liability		
Oil and natural gas properties	26,412	41,336
Other	32	3,375
Total deferred tax liability	26,444	44,711
Net deferred tax asset	$61,608	$64,383

Prior to 2012, the Company carried a full valuation allowance against its net deferred tax assets. The Company considered both the positive and negative evidence in determining whether it was more likely than not that its deferred tax assets were recoverable. The Company incurred a loss in 2008, primarily as a result of a write-down of its oil and natural gas properties following the ceiling test, which created a loss on an aggregate basis for the three-year period ended December 31, 2008. Primarily as a result of recent cumulative losses, the Company established a full valuation allowance as of December 31, 2008, and continued to carry the full valuation allowance each reporting period until December 31, 2011. At December 31, 2011, after considering all available positive and negative evidence, including the Company's profitable operations from 2009 to 2011 which resulted in income on an aggregate basis for the three year period ended December 31, 2011, and future operating results based on proved reserves, the Company determined that it was more likely than not that it would fully utilize its deferred tax assets recorded at December 31, 2011. Therefore, the Company reversed its valuation allowance at December 31, 2011.

If not utilized, the Company's federal operating loss ("NOL") carryforwards will expire as follows:

		Year Expiring				
	Total	2014-2019	2020-2022	2023-2025	2026-2028	2029-2033
Federal NOL carryforwards	$201,042	$—	$48,986	$65,878	$32,714	$53,464

The Company has limited state taxable income. Accordingly, the Company has established a full valuation allowance on the tax benefits associated with the state net operating loss carryforwards of approximately$167,795 which expire in years through 2033, as the Company does not anticipate generating taxable state income in the states in which these carryforwards apply. These amounts are not included in the deferred tax summary table above.

In 2009, the Company began to shift its operational focus from exploration, development and production in the Gulf of Mexico to the acquisition and development of onshore properties. This shift in exploration and development activity resulted in an increase in Texas income from production. This, coupled with the Company's exit from the Gulf of Mexico (the sale of its interest in the Habanero field in December 2012 and the Medusa field in December 2013), results in a change in the projected future Texas state tax rate beyond 2013 as a component of overall anticipated future taxes.

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The Company had no significant unrecognized tax benefits at December 31, 2013. Accordingly, the Company does not have any interest or penalties related to uncertain tax positions. However, if interest or penalties were to be incurred related to uncertain tax positions, such amounts would be recognized in income tax expense. Tax periods for years 2001 through 2013 remain open to examination by the federal and state taxing jurisdictions to which the Company is subject.

Below is a reconciliation of the reported amount of income tax expense attributable to continuing operations to the amount of income tax expense that would result from applying domestic federal statutory tax rates to pretax income from continuing operations.

	For the Years Ended December 31,		
Component of Income Tax Rate Reconciliation	2013	2012	2011
Income tax expense computed at the statutory federal income tax rate	35 %	35 %	35 %
Change in valuation allowance	— %	— %	(227)%
Percentage depletion carryforward	(8)%	(22)%	(3)%
State taxes net of federal benefit	4 %	6 %	— %
Restricted stock and stock options	5 %	2 %	— %
Section 162(m)	6 %	22 %	— %
Other	— %	4 %	4 %
Effective income tax rate	42 %	47 %	(191)%

	For the Years Ended December 31,		
Components of Income Tax Expense	2013	2012	2011
Current federal income tax benefit	$—	$—	$—
Current state income tax expense	326	110	—
Deferred federal income tax expense	2,652	1,777	13,176
Deferred state income tax expense	126	336	—
Valuation allowance	—	—	(82,459)
Total income tax expense (benefit)	$3,104	$2,223	$(69,283)

NOTE 11 – Asset Retirement Obligations

The following table summarizes the activity for the Company's asset retirement obligations:

	For the Year Ended December 31,	
	2013	2012
Asset retirement obligations at beginning of the period	$13,301	$13,938
Accretion expense	1,785	2,253
Liabilities incurred	679	205
Liabilities settled	(457)	(1,073)
Liabilities related to oil and gas properties sold	(4,765)	(877)
Revisions to estimate	(3,811)	(1,145)
Asset retirement obligations at end of period	6,732	13,301
Less: current asset retirement obligations	(4,120)	(2,336)
Long-term asset retirement obligations at the end of the period	$2,612	$10,965

Certain of the Company’s operating agreements require that assets be restricted for future abandonment obligations. Amounts recorded on the Consolidated Balance Sheets at December 31, 2013 as long-term restricted investments were $3,806. These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company’s oil and natural gas properties.

On December 5, 2013, the Company closed on its agreement to sell its interest in the Medusa field, Medusa Spar LLC, and substantially all of its Gulf of Mexico shelf properties to W&T Offshore, Inc. (“W&T”). Under the agreement, W&T will assume an estimated $4,765 of the ARO related to these offshore assets.

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(All amounts in thousands, except well, acreage, per-share and per-derivative instrument data)

The Company’s total revisions to estimates of $3,811 for the year ended December 31, 2013 relate to downward revisions related to the changes in the expecting timing of the abandonment.

NOTE 12 – Supplemental Information on Oil and Natural Gas Operations (Unaudited)

Oil and Natural Gas Properties

The following table discloses certain financial data relating to the Company’s oil and natural gas activities, all of which are located in the United States.

	For the Year Ended December 31,		
Capitalized costs incurred:	2013	2012	2011
Evaluated Properties-			
Beginning of period balance	$1,497,010	$1,421,640	$1,316,677
Capitalized G&A	10,014	12,148	11,205
Property acquisition costs	10,885	2,075	—
Exploration costs	147,164	22,703	5,473
Development costs	36,504	38,444	88,285
End of period balance	$1,701,577	$1,497,010	$1,421,640
Unevaluated Properties (excluded from amortization):			
Beginning of period balance	$68,776	$2,603	$8,106
Acquisitions	2,259	29,590	2,422
Exploration	10,767	34,674	1,372
Capitalized interest	4,410	2,109	573
Transfers to evaluated	(42,990)	(200)	(9,870)
End of period balance	$43,222	$68,776	$2,603
Accumulated depreciation, depletion and amortization:			
Beginning of period balance	$1,296,265	$1,208,331	$1,155,915
Provision charged to expense	42,251	48,524	52,416
Sale of mineral interests	82,096	39,410	—
End of period balance	$1,420,612	$1,296,265	$1,208,331

Unevaluated property costs primarily include lease acquisition costs incurred at federal lease sales, unevaluated drilling costs, seismic, capitalized interest and certain overhead costs related to exploration and development. These costs are directly related to the acquisition and evaluation of unproved properties and major development projects. The excluded costs and related reserves are included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. The Company expects that the majority of these costs will be evaluated over the next three but within five years. The Company’s unevaluated property balance decreased by $25,554 to $43,222 at December 31, 2013 compared to December 31, 2012. A significant portion of this decrease relates to the transfer of drilling and completion costs from the unevaluated property base to the evaluated property base.

Subsequent to December 31, 2013 and through March 10, 2014, the Company completed six horizontal exploration wells, drilled four horizontal wells and had two in progress. Additionally, the Company drilled two vertical exploratory wells and will be evaluating the results.

Depletion per unit-of-production (BOE) amounted to $31.12, $31.56 and $26.42 for the years ended December 31, 2013, 2012, and 2011, respectively. Lease operating expense per unit-of-production (BOE) amounted to $14.00, $14.81, and $9.92 for the years ended December 31, 2013, 2012, and 2011, respectively.

Under the full-cost accounting rules of the SEC, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full-cost ceiling amount). These rules generally require pricing based on the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the "ceiling" is exceeded. Given the volatility of oil and natural gas prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and natural gas properties could occur in the future. For the years ended December 31, 2013, 2012, and 2011, the Company recorded no impairment charges related to its oil and natural gas properties as a result of this calculation.

Estimated Reserves

The Company's proved oil and natural gas reserves at December 31, 2013, 2012 and 2011 have been estimated by Huddleston & Co., Inc., the Company's independent petroleum engineers. The reserves were prepared in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represents estimates only, and should not be deemed exact. In addition, the standardized measure of discounted future net cash flows should not be construed as the current market value of the Company's oil and natural gas properties or the cost that would be incurred to obtain equivalent reserves.

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Changes in the estimated net quantities of oil and natural gas reserves, all of which are located onshore within the continental United States and offshore within the Gulf of Mexico, are as follows:

	Reserve Quantities		
	For the year ended December 31,		
	2013	2012	2011
Proved developed and undeveloped reserves:			
Oil (MBbls):			
Beginning of period	10,780	10,075	8,149
Revisions to previous estimates	(2,540)	(488)	(110)
Purchase of reserves in place	150	38	—
Sale of reserves in place	(3,294)	(504)	(30)
Extensions and discoveries	7,713	2,636	3,062
Production	(911)	(977)	(996)
End of period	11,898	10,780	10,075
Natural Gas (MMcf):			
Beginning of period	19,753	35,118	32,957
Revisions to previous estimates	(5,351)	(10,838)	486
Purchase of reserves in place	317	115	—
Sale of reserves in place	(4,576)	(4,404)	(308)
Extensions and discoveries	10,619	3,350	7,064
Production	(3,011)	(3,588)	(5,081)
End of period	17,751	19,753	35,118
Proved developed reserves:			
Oil (MBbls):			
Beginning of period	4,955	5,069	4,503
End of period	5,960	4,955	5,069
Natural Gas (MMcf):			
Beginning of period	10,680	11,605	12,715
End of period	9,059	10,680	11,605
MBOE:			
Beginning of period	6,735	7,003	6,622
End of period	7,470	6,735	7,003
Proved undeveloped reserves:			
Oil (MBbls):			
Beginning of period	5,825	5,006	3,645
End of period	5,938	5,825	5,006
Natural Gas (MMcf):			
Beginning of period	9,073	23,513	20,241
End of period	8,692	9,073	23,513
MBOE			
Beginning of period	7,337	8,925	7,019
End of period	7,387	7,337	8,925

Total Proved Reserves: The Company ended 2013 with estimated net proved reserves of 14,857 MBOE, representing a 6% increase over 2012 year-end estimated net proved reserves of 14,072 MBOE. The increase is primarily due the

Company's development of its Permian basin, on which it drilled a total of 26 oil wells during 2013. The increase is offset by the sale of the Company's interest in the Medusa field and due to the Company's reclassification of certain vertical PUD locations to the horizontal probable and PUD categories.

Extrapolation of performance history and material balance estimates were utilized by the Company's independent petroleum and geological firm to project future recoverable reserves for the producing properties where sufficient history existed to suggest performance trends and where these methods were applicable to the subject reservoirs. The projections for the remaining producing properties were necessarily based on volumetric calculations and/or analogy to nearby producing completions. Reserves assigned to nonproducing zones and undeveloped locations were projected on the basis of volumetric calculations and analogy to nearby production, and to a small extent, horizontal PDP and PUD categories.

Notes to the Consolidated Financial Statements (All amounts in thousands, except well, acreage, per-share and per-derivative instrument data)

Proved Undeveloped Reserves: The Company annually reviews its proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. Generally, reserves for the Company's onshore properties are booked as PUDs only if the Company has plans to convert the PUDs into proved developed reserves within five years of the date they are first booked as PUDs. The Company's PUDs increased 1% to 7,387 MBOE from 7,337 MBOE at December 31, 2013 and 2012, respectively. The Company added 5,168 MBOE to its PUDs, primarily from the continued horizontal development of its Permian Basin properties. The increase in Permian Basin PUDs was partially offset by the reclassification of 3,724 MBOE, or 51%, included in the year-end 2012 PUD reserves related to vertical PUD locations that were reclassified to the horizontal probable, and to a small extent, horizontal PDP and PUD categories. The reclassified vertical PUDs include Wolfberry PUD locations that included certain target zones that are now expected to be more efficiently developed by the Company's multi-level horizontal drilling programs initiated in 2012. Also offsetting the Permian Basin PUD growth were the sale of 1,297 MBOE, or 18%, included in the year-end 2012 PUD reserves related to our Medusa field and the conversion of a small portion of 2012 PUD reserves to PDPs during 2013 from the drilling of vertical wells.

The Company's PUDs decreased 18% to 7,337 MBOE from 8,925 MBOE at December 31, 2012 and 2011, respectively. Additions during the year added 2,344 MBOE to the Company's PUDs, offset by (1) 557 MBOE primarily comprised of transfers to PDPs as a result of our development program, (2) 1,148 MBOE related to the sale of Habanero, and (3) 2,227 MBOE related to reductions in our PUD reserves, primarily related to the Haynesville Shale, by amounts no longer deemed to be economic PUDs at year-end. Of the Company's year-end 2011 PUD reserves, 6% were converted to proved developed producing reserves by year end 2012, at a total cost of approximately $19 million, net.

Of the Company's 2012 PUDs, 1,297 MBOE were attributable to the Company's offshore properties in the Medusa field in the Gulf of Mexico. As previously noted, the Company sold its interest in the Medusa field during 2013.

Standardized Measure

The following tables present the standardized measure of future net cash flows related to estimated proved oil and natural gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2013. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the tables below, represent the fair value of our estimated oil and natural gas reserves. Prices are based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. The following table summarizes the average 12-month oil and natural gas prices net of differentials for the respective periods:

	2013	2012	2011
Average 12-month price, net of differentials, per Mcf of natural gas	$5.45	$4.81	$5.60
Average 12-month price, net of differentials, per barrel of oil	$92.16	94.68	98.98

Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

Natural gas production from our deepwater and Permian Basin properties has a high Btu content of separator natural gas. The natural gas Mcf prices of $5.45 and $4.81 used in the 2013 and 2012 reserve estimates include adjustments to reflect the Btu content, transportation charges and other fees specific to the individual properties. The oil prices of $92.16 and $94.68 used in the 2013 and 2012 reserve estimates have been adjusted to reflect all wellhead deductions and premiums on a property-by-property basis, including transportation costs, location differentials and crude quality.

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	Standardized Measure For the year ended December 31,		
	2013	2012	2011
Future cash inflows	$1,193,299	$1,115,570	$1,194,079
Future costs -			
Production	(357,005)	(249,329)	(356,653)
Development and net abandonment	(155,667)	(273,817)	(268,628)
Future net inflows before income taxes	680,627	592,424	568,798
Future income taxes	(68,239)	(55,772)	(78,813)
Future net cash flows	612,388	536,652	489,985
10% discount factor	(328,442)	(305,504)	(219,628)
Standardized measure of discounted future net cash flows	$283,946	$231,148	$270,357

	Changes in Standardized Measure For the year ended December 31,		
	2013	2012	2011
Standardized measure at the beginning of the period	$231,148	$270,357	$198,916
Changes			
Sales and transfers, net of production costs	(78,661)	(84,044)	(107,297)
Net change in sales and transfer prices, net of production costs	(46,088)	47,261	125,518
Net change due to purchases and sales of in place reserves	(145,711)	(35,665)	1,275
Extensions, discoveries, and improved recovery, net of future production and development costs incurred	212,431	53,446	22,598
Changes in future development cost	153,983	39,815	(83,110)
Revisions of quantity estimates	(68,958)	(77,322)	(949)
Accretion of discount	25,010	30,989	68,384
Net change in income taxes	1,751	13,969	(32,918)
Changes in production rates, timing and other	(959)	(27,658)	77,940
Aggregate change	52,798	(39,209)	71,441
Standardized measure at the end of period	$283,946	$231,148	$270,357

NOTE 13 – Other

Commitments and Contingencies: The Company is involved in various claims and lawsuits incidental to its business. In the opinion of management, the ultimate liability hereunder, if any, will not have a material adverse effect on the financial position or results of operations of the Company.

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

Global Settlement with Joint Interest Partner: During 2011, the Company and a joint interest partner entered into a settlement agreement related to various disputes. All matters were settled and as result of the settlement agreement the Company received an interest in other specialized deep water property and equipment. The Company recognized a gain of $5,041 as a result of the settlement and classified the property and equipment received as held for sale assets, included within other property and equipment since the Company had no use for this type of equipment in its operations. Since the settlement with its joint interest partner, the Company has sold a portion of these assets and has continued to actively market the remaining assets throughout 2012 and 2013. During 2012, after selling assets valued at $527 during the year, the Company determined that certain equipment components were not usable without additional rework and thus recorded an impairment charge to its Statement of Operations of $1,177 during

2012. During 2013, after selling assets value at $114 during the year, the Company has made a decision to abandon the equipment. As such the Company recorded an impairment charge of $1,707 to its Statement of Operations, representing the remaining value of this equipment.

Operating Leases: In April 2012, the Company took delivery of a drilling rig (the "Cactus 1 Rig") for a term of two years, which it subsequently renewed on March 6, 2014 for an additional two year term ending April 2016. On August 1, 2013, the Company contracted a second horizontal drilling rig (the "Patterson Rig") for a one-year term, though the Company provided notice on February 17, 2014 that it will cancel its Patterson rig contract on or about March 17, 2014. Under the early termination provisions of the agreement, estimated termination payments for this rig will be approximately $2,055 in 2014. Should the lessor be able to re-charter the rig, the termination payments would be reduced. To replace the Patterson Rig, the Company contracted a replacement rig (the "Cactus 2 Rig") for a term of two years, which is scheduled to commence operations on April 1, 2014. Similar to the Patterson Rig, the Cactus 1 and 2 Rig lease agreements also include early termination provisions that would reduce the minimum rentals under the agreement, assuming the lessor is unable to re-charter the rig and staffing personnel to another lessee. Lease costs recorded during 2013 were $12,860. Lease payments as of December 31, 2013 will approximate $13,954, $9,308 and $2,295 in 2014, 2015 and 2016, respectively. Including the additional lease commitments executed subsequent to December 31, 2013, the Company's drilling rig lease commitments as of March 10, 2014 are $19,732, $18,250 and $4,500 in 2014, 2015, and 2016, respectively.

Property Acquisitions and Dispositions

Acquisitions

During the second quarter of 2013, the Company acquired approximately 2,468 gross (2,186 net) acres in Reagan and Upton Counties, Texas, which is located in the southern portion of the Midland Basin and which is prospective for both horizontal and vertical drilling. The acquisition also included seven gross vertical wells and 1,301 barrels of oil equivalent proved reserves. The purchase price of $11,000 was funded using a portion of the proceeds from the preferred stock offering (discussed in Note 9).

During the first quarter of 2012, the Company acquired approximately 16,233 gross (14,653 net) acres in Borden County, which is located in the northern Midland basin. The northern Midland basin has had limited drilling activity compared with the southern Midland basin (where our current production is located), increasing the economic risk related to these drilling activities. The purchase price of $14,538 was funded from existing cash balances. During the third quarter of 2012, we acquired an additional 8,095 gross acres (6.964 net) in this area for a total consideration of $4,835.

During the second quarter of 2012, the Company signed a purchase and sale agreement to acquire 2,319 gross (1.762 net) acres in southern Reagan County, Texas for a total purchase price of $12,012, which was financed with a draw on the Credit Facility. The transaction had an effective date of May 1, 2012 and closed on July 5, 2012.

Dispositions

During the fourth quarter of 2013, the Company closed on the sale of its 15.0% working interest in the Medusa field (Mississippi Canyon blocks 582 and 538), our 10.0% membership interest in Medusa Spar LLC, and substantially all of our remaining Gulf of Mexico shelf properties. The Company sold its interest in Medusa to W&T, an unrelated third-party, for a total net cash consideration of approximately $88,000 after customary purchase price adjustments.

Also during the fourth quarter of 2013, the Company closed on the sale of its 69% interest in the Swan Lake field for $2,000. This was the Company’s only field in the Haynesville shale. Consistent with the Company’s accounting policy discussed in Note 2, the proceeds from these sales were accounted for as a reduction to capitalized costs as the sale did not significantly alter the relationship between capitalized costs and proved reserves.

Effective December 28, 2012, the Company closed on the sale of its 11.25% working interest in the Habanero field (Garden Banks Block 341). The Company sold its interest in Habanero to Shell Offshore Inc., a subsidiary of Royal Dutch Shell Plc, for an estimated net cash consideration of $39,410 after customary purchase price adjustments. As noted above, the proceeds from this sale were accounted for as a reduction to capitalized costs as the sale did not significantly alter the relationship between capitalized costs and proved reserves.

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NOTE 14 – Summarized Quarterly Financial Information (Unaudited)

2013	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$22,541	$22,760	$30,797	$26,471
Income from operations	898	957	6,345	2,464
Net income (loss)	(800)	758	1,082	3,264
Income (loss) available to common shares	(800)	78	(892)	1,291
Income (loss) per common share - basic	$(0.02)	$0.00	$(0.02)	$0.03
Income (loss) per common share - diluted	$(0.02)	$0.00	$(0.02)	$0.03

2012	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$29,294	$25,360	$27,402	$28,677
Income from operations	2,716	2,759	2,563	2,652
Income (loss) available to common shares	488	3,799	(1,105)	(435)
Income (loss) per common share - basic	$0.01	$0.10	$(0.03)	$(0.01)
Income (loss) per common share - diluted	$0.01	$0.09	$(0.03)	$(0.01)

ITEM 9. Changes In and Disagreements With Accountants on Accounting and Financial Disclosure

There have been no disagreements with the independent auditors on any matters of accounting principles or practices, financial statement disclosure, or auditing scope or procedures.

ITEM 9A. Controls and Procedures

Disclosure Controls and Procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is accumulated and communicated to the issuer's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. The Company's principal executive and principal financial officers have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) were effective as of December 31, 2013.

Management's Report on Internal Control over Financial Reporting. Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control structure is designed to provide reasonable assurance to our management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of our financial statements prepared for external purposes in accordance with U.S. generally accepted accounting principles. Under the supervision and with the participation of our management, including our CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2013 based on the framework in Internal Control – Integrated Framework published by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission (1992 framework)(the COSO criteria). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2013.

Because of its inherent limitations, internal control over financial reporting can provide only reasonable assurance that the objectives of the control system are met and may not prevent or detect misstatements. In addition, any evaluation of the effectiveness of internal controls over financial reporting in future periods is subject to risk that those internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's independent registered public accounting firm has issued an attestation report regarding its assessment of the Company's internal control over financial reporting as of December 31, 2013, which follows Part II, Item 9B of this filing. Additionally, the financial statements for each of the years covered in this Annual Report on Form 10-K have been audited by an independent registered public accounting firm, Ernst & Young LLP whose report is presented immediately preceding the Company's financial statements included in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

ITEM 9A (T). Controls and Procedures

See Item 9A.

ITEM 9B. Other Information

Submissions of Matters to a Vote of the Security Holders

None.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Callon Petroleum Company

We have audited Callon Petroleum Company's internal control over financial reporting 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 (1992 framework)(the COSO criteria). Callon Petroleum 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 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Callon Petroleum Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Callon Petroleum Company as of December 31, 2013 and 2012, and the related statements of operations, comprehensive income, cash flow, and changes in stockholders' equity (deficit) for each of the three years in the period ended December 31, 2013, and our report dated March 12, 2014 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 12, 2014

PART III.

ITEM 10. Directors, Executive Officers and Corporate Governance

For information concerning Item 10, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 15, 2014 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

The Company has adopted a code of ethics that applies to the Company's chief executive officer, chief financial officer and chief accounting officer. The full text of such code of ethics has been posted on the Company's website at www.callon.com, and is available free of charge in print to any shareholder who requests it. Request for copies should be addressed to the Secretary at mailing address Post Office Box 1287, Natchez, Mississippi 39121.

ITEM 11. Executive Compensation

For information concerning Item 11, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 15, 2014 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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

For information concerning the security ownership of certain beneficial owners and management, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 15, 2014 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 13. Certain Relationships and Related Transactions and Director Independence

For information concerning Item 13, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 15, 2014 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services

For information concerning Item 14, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 15, 2014 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

PART IV.
ITEM 15. Exhibits

Exhibit			Description
1			The following is an index to the financial statements and financial statement schedules that are filed in Part II, Item 8 of this report on Form 10-K.
			Report of Independent Registered Public Accounting Firm
			Consolidated Balance Sheets as of December 31, 2013 and 2012
			Consolidated Statements of Operations for each of the three years in the period ended December 31, 2013
			Consolidated Statements of Stockholders' Equity (Deficit) for each of the three years in the Period Ended December 31, 2013
			Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2013
			Notes to Consolidated Financial Statements
2			Schedules other than those listed above are omitted because they are not required, not applicable or the required information is included in the financial statements or notes thereto.
3		Exhibits	
	2		Plan of acquisition, reorganization, arrangement, liquidation or succession*
	3		Articles of Incorporation and Bylaws
		3.1	Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
		3.2	Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
		3.3	Certificate of Amendment to Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
		3.4	Certificate of Amendment to the Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.4 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-14039)
	4		Instruments defining the rights of security holders, including indentures
		4.1	Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
		4.2	Rights Agreement between Callon Petroleum Company and American Stock Transfer & Trust Company, Rights Agent, dated March 30, 2000 (incorporated by reference from Exhibit 99.1 of the Company's Registration Statement on Form 8-A, filed April 6, 2000, File No. 001-14039)
		4.3	Indenture for the Company's 13.00% Senior Notes due 2016, dated November 24, 2009, between Callon Petroleum Company, the subsidiary guarantors described therein, Regions Bank and American Stock Transfer & Trust Company (incorporated by reference to Exhibit T3C to the Company's Form T3, filed November 19, 2009, File No. 022-28916)
		4.4	Certificate of Designations of 10% Cumulative Preferred Stock (incorporated by reference to Exhibit 3.5 of the Company's Form 8-A filed May 23, 2013)
		4.5	Certificate for the Company's 10% Cumulative Preferred Stock (incorporated by reference to Exhibit 4.1 of the Company's Form 8-A filed May 23, 2013
		4.6	Amendment to the Certificate of Incorporation increasing the number of authorized shares of common stock [Filed herewith]
	9		Voting trust agreement
			None

10		Material contracts
	10.1	Callon Petroleum Company 1994 Stock Incentive Plan (incorporated by reference from Exhibit 10.5 of the Company's Registration Statement on Form 8-B, filed October 3, 1994)
	10.2	Callon Petroleum Company 1996 Stock Incentive Plan as amended on May 9, 2000 (incorporated by reference from Appendix I of the Company's Definitive Proxy Statement on Schedule 14A, filed March 28, 2000, File No. 001-14039)

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10.3	Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)
10.4	Amendment No. 3 to the Callon Petroleum Company 1996 Stock Incentive Plan (incorporated by reference from Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)
10.5	Amendment No. 1 to the Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference from Exhibit 10.2 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)
10.6	Callon Petroleum Company Amended and Restated 2006 Stock Incentive Plan (incorporated by reference from Exhibit 10.3 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)
10.7	Callon Petroleum Company 2009 Stock Incentive Plan effective as of April 30, 2009 (incorporated by reference from Exhibit A to the Company's Definitive Proxy Statement on Schedule 14A, filed March 30, 2009, File No. 001-14039)
10.8	Amendment to the Callon Petroleum Company 1996 Stock Incentive Plan effective as of August 7, 2009 (incorporated by reference from Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2009, File No. 001-14039)
10.9	Callon Petroleum Company 2010 Phantom Share Plan, adopted May 4, 2010 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on May 7, 2010)
10.10	Form of Callon Petroleum Company Phantom Share Award Agreement, adopted May 4, 2010 (incorporated by reference to Exhibit 10.2 of the Company's current Report on Form 8-K filed on May 7 , 2010)
10.11	Deferred Compensation Plan for Outside Directors; Callon Petroleum Company (effective as of January 1, 2011) (incorporated by reference to Exhibit 10.17 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-14039)
10.12	Amended and Restated Severance Compensation Agreement, dated as of March 15, 2011 and effective as of January 1, 2011, by and between Fred L. Callon and Callon Petroleum Company (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on March 18, 2011)
10.13	Form of Amended and Restated Severance Compensation Agreement, dated as of March 15, 2011 and effective as of January 1, 2011, by and between Callon Petroleum Company and its executive officers (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed on March 18, 2011)
10.14	Severance Compensation Agreement, dated as of September 21, 2011, by and between Gary A. Newberry and Callon Petroleum Company (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on September 21, 2011)
10.15	Fourth Amended and Restated Credit Agreement dated as of June 20, 2012, by and among the Company, the "Lenders" described therein, and Regions Bank as the sole arranger and administrative agent (incorporated by reference from Exhibit 10.1 on Form 8-K, filed June 25, 2012, File No. 001-14039)
10.16	Fourth Amended and Restated Revolving Promissory Note dated June 20, 2012 (incorporated by reference from Exhibit 10.1 on Form 8-K, filed June 25, 2012, File No. 001-14039)
10.17	Fourth Amended and Restated Guaranty Agreement dated June 20, 2012 (incorporated by reference from Exhibit 10.1 on Form 8-K, filed June 25, 2012, File No. 001-14039)
10.18	Master Assignment, Agreement and Amendment No. 1 to the Fourth Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.1 on Form 8-K, filed October 16, 2012, File No. 001-14039)
10.19	

	Purchase and Sale Agreement by and between Shell Offshore Inc. and Callon Petroleum Operating Company dated as of November 27, 2012.
10.20	Callon Petroleum Company 2011 Omnibus Incentive Plan (incorporated by reference from Exhibit A of the Company's Definitive Proxy Statement on Schedule 14A filed March 21, 2011, File No. 14039)
10.21	Purchase and Sale Agreement by and between W&T Offshore, Inc. and Callon Petroleum Company dated as of December 5, 2013
10.22	Underwriting Agreement relating to the Company's 10% Cumulative Preferred Stock (incorporated by reference to Exhibit 1.1 of the Company's Form 8-K filed on May 28, 2013).

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	10.23	Agreement, dated March 9, 2014, among the Company and Lone Star Value Investors, L.P., Lone Star Value Co-Invest I, L.P., Lone Star Value Investors GP, LLC, Lone Star Value Management, LLC, Jeffery E. Eberwein and Matthew R. Bob (incorporated by reference from Exhibit 10.1 on Form 8-K, filed on March 10, 2014, File No. 001-14039)
11		Statement re computation of per share earnings*
12		Statements re computation of ratios*
13		Annual Report to security holders, Form 10-Q or quarterly reports*
14		Code of Ethics
	14.1	Code of Ethics for Chief Executive Officers and Senior Financial Officers (incorporated by reference to Exhibit 14.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
16		Letter re change in certifying accountant*
18		Letter re change in accounting principles*
21		Subsidiaries of the Company
	21.1	Subsidiaries of the Company
22		Published report regarding matters submitted to vote of security holders*
23		Consents of experts and counsel
	23.1	Consent of Ernst & Young LLP
	23.2	Consent of Huddleston & Co., Inc.
24		Power of attorney*
31		Rule 13a-14(a) Certifications
	31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)
	31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)
32		Section 1350 Certifications of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)
99		Additional Exhibits
	99.1	Reserve Report Summary prepared by Huddleston and Co. as of December 31, 2013
101		Interactive Data Files **

*	Not applicable to this filing
**	Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability.

SIGNATURES

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

Date:	March 12, 2014	/s/ Fred L. Callon Fred L. Callon (principal executive officer, director)
Date:	March 12, 2014	/s/ B. F. Weatherly B. F. Weatherly (principal financial officer, director)
Date:	March 12, 2014	/s/ Rodger W. Smith Rodger W. Smith (principal accounting officer)
Date:	March 12, 2014	/s/ L. Richard Flury L. Richard Flury (director)
Date:	March 12, 2014	/s/ John C. Wallace John C. Wallace (director)
Date:	March 12, 2014	/s/ Anthony J. Nocchiero Anthony J. Nocchiero (director)
Date:	March 12, 2014	/s/ Larry D. McVay Larry McVay (director)

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

Date:	March 12, 2014	/s/ B. F. Weatherly B. F. Weatherly, Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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