CALLON PETROLEUM CO
Form 10-K
March 13, 2014

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

FORM 10-K

ý ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013
OR
¨ TRANSITION REPORT UNDER SECTION 13 OR 15(D) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-14039

Callon Petroleum Company
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	64-0844345 (IRS Employer Identification No.)
200 North Canal Street Natchez, Mississippi (Address of Principal Executive Offices)	39120 (Zip Code)

(Registrant's Telephone Number, Including Area Code): 601-442-1601
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 par value	New York Stock Exchange
10.0% Series A Cumulative Preferred Stock	New York Stock Exchange

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

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No ý
Indicate by check mark whether the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý
Indicate by check mark whether registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of “large accelerated filer,” “accelerated filer,” and “smaller reporting company” in Rule 12b-2 of the Exchange Act (check one):

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2013 was approximately $129.6 million.

As of March 10, 2014, 40,465,227 shares of the Registrant’s common stock, par value $.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 2013) relating to the Annual Meeting of Stockholders to be held on May 15, 2014, which are incorporated into Part III of this Form 10-K.

TABLE OF CONTENTS

Special Note Regarding Forward Looking Statements

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve quantities, present value and growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as “anticipate,” “project,” “intend,” “estimate,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “plan,” “forecast,” “target” or si

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for commodities (including regional basis differentials),
- our ability to transport our production to the most favorable markets or at all,
- the timing and extent of our success in discovering, developing, producing and estimating reserves,
- our ability to fund our planned capital investments,
- the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives,
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services,
- our future property acquisition or divestiture activities,
- the effects of weather,
- increased competition,
- the financial impact of accounting regulations and critical accounting policies,
- the comparative cost of alternative fuels,
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed,
- credit risk relating to the risk of loss as a result of non-performance by our counterparties, and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission.

We caution you that the forward-looking statements contained in this Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2013 and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document:

- 3-D: three-dimensional.
- ARO: Asset Retirement Obligation.
- Bbl or Bbls: barrel or barrels of oil or natural gas liquids.
- Bcf: billion cubic feet.
- BOE: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas. The ratio of one barrel of oil or NGL to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- BOE/d: BOE per day.
- BLM: Bureau of Land Management.
- BOEM: Bureau of Ocean Energy Management, Regulation and Enforcement; formerly the Minerals Management Service.
- Btu: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- BSEE: Bureau of Safety and Environmental Enforcement.
- DOI: Department of Interior.
- EPA: Environmental Protection Agency.
- GHG: greenhouse gases.
- LIBOR: London Interbank Offered Rate.
- LOE: lease operating expense.
- MBbls: thousand barrels of oil.
- MBOE: thousand boe.
- MBOE/d: Mboe per day.
- Mcf: thousand cubic feet of natural gas.
- Mcfe: thousand cubic feet of natural gas equivalents.
- Mcf/d: Mcf per day.
- MMBbls: million barrels of oil.
- MMBOE: million BOE.
- MMBtu: million Btu.
- MMcf: million cubic feet of natural gas.
- MMcf/d: MMcf per day.
- MMS: Minerals Management Service.
- NGL or NGLs: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- NYMEX: New York Mercantile Exchange.
- oil: includes crude oil and condensate.
- PDPs: proved developed producing reserves.
- PDNPs: proved developed non-producing reserves.
- PUDs: proved undeveloped reserves.
- RSU: restricted stock units.
- SEC: United States Securities and Exchange Commission.
- GAAP: Generally Accepted Accounting Principles in the United States

With respect to information relating to our working interest in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I.
Items 1 and 2 - Business and Properties

Overview

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and natural gas properties since 1950. 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 unle the context requires otherwise.

In 2013, the Company completed its onshore strategic repositioning that began in 2009, shifting its operations from the offshore waters in the Gulf of Mexico to the onshore, Permian Basin in Texas. In the fourth quarter of 2013, the Company sold its interest in its only remaining deepwater property, the Medusa field, in addition to the sale of the Medusa spar facility and substantially all remaining offshore shelf properties. Previously, Callon sold its interest in its deepwater Habanero field in the fourth quarter of 2012. Collectively, these transactions completed the Company's transition to an onshore operator with an asset base concentrated exclusively in the Midland Basin, a sub-basin contained in the broader Permian Basin.

Callon exited 2013 with average Permian production in the month of December of 3,611 BOE/d (approximately 84% oil), a 129% increase over our exit rate in 2012. We believe that the Company's transition to a horizontal development program, which was expanded from two fields to four fields in late 2013, has improved Callon's overall capital efficiency and has contributed to a net increase of 59% in the Company's Permian proven reserve base.

The Company operates 100% of its Permian acreage, which provides additional flexibility to modify development plans to address potential changes in the operating and commodity price environments. As of December 31, 2013, we had estimated net proved reserves of 11.9 MMBbls and 17.8 Bcf, or 14.9 MMBOE, all of which were located in the Permian Basin, compared with approximately 67% located in the Permian Basin at December 31, 2012. Additionally, 80% of our proved reserves were crude oil and 50% were proved developed at year-end 2013, on a BOE basis.

Our Business Strategy

Our goal is to enhance stockholder value through the execution of the following strategy:

Drive production and reserve growth through horizontal development of our resource base. Our initial drilling efforts in the Permian Basin targeted the development of multiple zones with vertical wells as part of the "Wolfberry" play. As part of this drilling program, we amassed a database related to the subsurface geology and rock characteristics over the last several years. This information, combined with our review of industry activity and best practices, provided the foundation for Callon to initiate the horizontal development of our resource base in 2012. Importantly, we believe horizontal development of our resource base will provide the opportunity to improve returns relative to vertical drilling by accessing a larger base of reserves in target zone with a lateral wellbore. During the fourth quarter of 2013, approximately 44% of our total Permian production was sourced from horizontal wells. We expect the contribution of horizontal production volumes from our existing properties to increase with the recent expansion of our horizontal development efforts to four fields as part of our current two-rig drilling program.

Expand our drilling portfolio through evaluation of existing acreage. Our horizontal development drilling efforts to date have been primarily focused on the Upper and Lower Wolfcamp B shales, establishing production from both zones in the Southern Midland Basin. We have been focused on these development zones to reduce drilling risk as we continue to grow our asset base in the Permian Basin. We believe additional opportunities exist to selectively target various other prospective zones including the Jo-Mill, Lower Spraberry, Wolfcamp A, Wolfcamp C and Cline formations, and plan to selectively drill potential identified locations to complement our core development efforts in the Wolfcamp B. Moreover, we will monitor the efficiency of our horizontal wells related to reservoir drainage over time and pursue downspacing initiatives within target zones if overall returns can be enhanced. We recently transitioned to closer spacing of our horizontal laterals in the Southern Midland Basin in both the Upper and Lower Wolfcamp B shales.

Outside of our core development areas in the Southern and Central Midland Basin, we maintain an exploration position in the Northern Midland Basin. Our current activity in the Northern Midland Basin is limited to vertical drilling in order to assess resource potential and economic returns. If our exploration concept is proven to economically produce hydrocarbons on a repeatable basis from vertical wells, we will then determine whether the testing of horizontal development concepts is warranted.

Pursue selective acquisitions in the Permian Basin. We have demonstrated our ability to acquire and trade acreage in the Midland Basin. Specifically, we added our Taylor Draw field in 2012 and Garrison Draw Field in 2013 for a total of $23 million, including acquired production and proved reserves. These two fields are now part of our core horizontal development plan. We have built on these acquisitions with recent acquisitions of acreage near our existing East Bloxom (see Recent Developments below), as well as completing an acreage trade at Garrison Draw which added contiguous acreage for effective long lateral horizontal development. We will continue to pursue leasehold acquisitions in the Permian Basin, and primarily in the Midland Basin, that have horizontal resource potential that can be further augmented by bolt-on acreage acquisitions and acreage trades over time.

Capitalize on opportunities to further reduce cost of capital. Following the disposition of our offshore properties, we have the opportunity to recapitalize the Company with a lower cost of capital commensurate with an improved credit risk profile as a purely onshore operator. As part of an ongoing effort to reduce our cost of capital, we have redeemed nearly $90 million of our 13% Senior Notes due 2016 (the “Senior Notes”) since 2011 and recently called for the redemption of the remaining $49 million of principal to occur in April 2014, replacing these Senior Notes with lower cost financing. Additionally, we believe the demonstrated growth in our proved developed reserve base provides the foundation for a meaningful expansion of our borrowing base capacity under our revolving credit agreement. We recently increased the notional amount and reduced the interest expense related to our revolving credit agreement, evidencing another step in reducing our overall cost of capital (see Recent Developments below).

Our Strengths

Established resource base and acreage position in the Permian Basin. Our production is exclusively from the Permian Basin in West Texas, an area that has supported production since the 1940s. The basin has well-established infrastructure from historical operations, and we believe the basin also benefits from a relatively stable regulatory environment that has been established over time. We have assembled a position of approximately 13,600 net acres in the Southern and Central Midland Basin that are prospective for multiple oil-bearing intervals that have been produced by us and other industry participants. As of December 31, 2013, our estimated net proved reserves were comprised of approximately 80% oil and 20% natural gas, which includes NGLs in the production stream. This oil exposure provides us the opportunity to benefit from currently more favorable prices as compared to natural gas.

Multi-year drilling inventory. Our current acreage position in the Permian Basin provides visible growth potential from a horizontal drilling inventory of almost 20 years based on our current two-rig horizontal drilling program. As of December 31, 2013, based upon the results of horizontal wells drilled by us and other offsetting operators, and our analysis of core data and historical vertical well performance, we have identified an inventory of approximately 540 potential horizontal well locations in multiple horizons across our Southern and Central Midland Basin acreage. Of these potential locations, approximately 225 are identified in the Upper Wolfcamp B, Lower Wolfcamp B and Wolfcamp A zones which have been drilled on our acreage and are currently producing.

Experienced team operating in the Permian Basin. We have assembled a management team experienced in acquisitions, exploration, development and production in the Midland Basin. Reflective of this experience, we have realized improvements in our drilling and capital efficiency since launching our horizontal drilling program in 2012. For example, our average drill time for a typical 7,800 foot lateral Wolfcamp shale well decreased from approximately 30 days at the start of our drilling program in 2012 to under 20 days as of February 2014. We continue to evaluate our completion techniques, and downspacing initiatives that we believe have the potential to improve resource recovery and contribute to enhanced returns on capital. In addition, we regularly evaluate our operating results against those of other operators in the area in an effort to benchmark our performance against the best performing operators and evaluate and adopt best practices.

High degree of operational control. We operate all of our Permian Basin acreage, providing us the opportunity to modify our operational plans to respond to changes in operational and commodity price environments. This operating control also allows us to modify drilling and completion techniques, and change drilling schedules as needed to manage the assimilation of newly acquired acreage that may have drilling commitments.

Operating culture focused on safety and the environment. We have established a Health, Safety and Environmental department dedicated to our operations in the Permian Basin. This group is responsible for monitoring the activity and safety compliance of both our employees as well as third party service providers and consultants. This department also coordinates closely with our operational team to ensure effective communication with appropriate regulatory bodies as well as landowners. We believe that our proactive efforts in this area have made a positive impact on our operations and culture. As an example, we were recently awarded the Midland Bruno Hanson/Midland College Award for Environmental Excellence which is given to companies that demonstrate strong environmental stewardship in the Permian Basin.

Financial flexibility to fund growth initiatives. We bolstered our capital structure in 2013 with the issuance of Series A Cumulative Preferred Stock and the sale of our offshore assets. We have continued to build upon these transactions with the recent completion of the Amended Credit Facility and Second Lien Facility as described in Recent Developments.

Exploration and Development Activities

Our 2013 total capital expenditures, on a cash basis and including acquisitions, were $171 million, representing a 17% increase over 2012 actual capital expenditures. Of the $171 million, approximately $145 million was allocated to onshore drilling, development and leasehold acquisition activity in the Permian basin. During 2013, capital expenditures for exploration and development costs related to oil and natural gas properties included the following expenditures (in millions):

Southern Midland Basin	$111
Central Midland Basin	20
Northern Midland Basin	7
Other	7
Total capital expenditures	145
Capitalized general and administrative costs allocated directly to exploration and development projects	11
Capitalized interest	4
Total capitalized expenses	15
Total operational expenditures	160
Acquisitions	11
Total capital expenditures, including acquisitions	$171

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 development of established Upper and Lower Wolfcamp zones in the Southern and Central Midland Basin. We also expect to drill 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. Planned vertical drilling activity is anticipated to be limited to five deep Wolfberry wells in the Pecan Acres field and one well in the Garrison Draw field. In addition, our plans include 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.

Recent Developments

Credit facilities

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.

Acquisitions

During the first quarter of 2014, we added 1,280 net acres in Upton County near our existing core development fields for an aggregate purchase price of $7.0 million. This acreage added an estimated 96 gross potential horizontal well locations from seven prospective zones to our drilling inventory. In addition, we expect to leverage existing infrastructure from our East Bloxom field in the development of this new acreage. See Notes 6 and 12 to our financial statements for additional information regarding acquisitions.

Table of Contents

Divestitures

Effective December 5, 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 these assets to W&T Offshore, Inc., an unrelated third-party, for total net cash consideration of approximately $100 million before customary purchase price adjustments. The Medusa field had production net to Callon of 582 MBOE in 2013. Also during the fourth quarter of 2013, the Company closed on the sale of its 69% interest in the Swan Lake field for $2 million. This field included 429 net acres and produced approximately 107 MMcf during the year ended December 31, 2013. This was the Company's only field in the Haynesville shale. See Note 12 to our financial statements for additional information.

Oil and Natural Gas Properties

As of December 31, 2013, our estimated net proved reserves totaled 14.9 MMBOE and included 11.9 MMBbls and 17.8 Bcf, with a pre-tax present value, discounted at 10%, of $301.1 million. Pre-tax present value is a non-GAAP financial measure, which we reconcile to the GAAP measure of standardized measure of $283.9 million in note (d) to the table below. Oil constituted approximately 80% of our total estimated equivalent net proved reserves and approximately 80% of our total estimated equivalent proved developed reserves.

The following table sets forth certain information about our estimated net proved reserves prepared by our independent petroleum reserve engineers by major area and for all other properties combined at December 31, 2013:

	Estimated Net Proved Reserves			Pre-tax Discounted Present Value
	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE) (a)	($000) (b)(c)(d)
Southern Midland Basin	10,103	15,021	12,607	$267,216
Central Midland Basin	1,699	2,730	2,154	39,336
Northern Midland Basin	96	—	96	3,921
Other (c)	—	—	—	(9,329)
Total	11,898	17,751	14,857	$301,144

(a) We convert Mcf to BOE using a conversion ratio of six Mcf to one Bbl. This ratio, which is typical in the industry and represents the approximate energy equivalent of a Mcf to a Bbl, does not reflect to market price equivalence of Mcf of natural gas compared with a Bbl of oil or NGLs. On a market price equivalence basis, a barrel of oil or NGLs has a substantially higher price than six Mcf of natural gas.

(b) Represents the present value of future net cash flows before deduction of federal income taxes, discounted at 10%, attributable to estimated net proved reserves as of December 31, 2013, as set forth in the Company's reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc.

(c) Includes a reduction for estimated plugging and abandonment costs that are reflected as a liability on our balance sheet at December 31, 2013, in accordance with accounting for asset retirement obligations rules. These obligations were retained following the sale of our offshore operations. The negative Pre-Tax Discounted Present Value of the "Other" reflects plugging and abandonment obligations exceeding the future net cash flows.

(d) The Company uses the financial measure "Pre Tax Discounted Present Value" which is a non-GAAP financial measure. The Company believes that Pre Tax Discounted Present Value, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total standardized measure calculated in accordance with the guidance issued by the FASB for disclosures about oil and gas producing activities for our proved reserves as of December 31, 2013 was $283.9 million inclusive of the $17.2 million discounted estimated future income taxes relating to such future net revenues. The projected per Mcf natural gas price of $5.45 used in the 2013 reserve estimates has been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected per barrel oil price of $92.16 used in the 2013 reserve estimates has been adjusted to reflect all wellhead deductions and premiums on a property-by-property basis, including transportation costs, location differentials and crude quality.

Permian Basin

As of December 31, 2013, we owned approximately 31,829 net acres in the Permian Basin. Our reserves in the Permian Basin represent all of our proved reserves at year-end 2013 as compared to 67% at year-end 2012. Average net production from the Company's Permian Basin properties increased 38% to 2,227 BOE/d in 2013 from 1,619 BOE/d in 2012. As of December 2013, our average daily net production from the Permian Basin was 3,611 BOE/d.

Southern Midland Basin

- Counties (fields): Upton (East Bloxom), Reagan (Taylor Draw and Garrison Draw) and Crockett (Block 5)
- 8,904 net acres as of December 31, 2013
- 77 producing wells (17 horizontal)
- Initiated horizontal development in 2012
- 4th quarter 2013 net production: 2,334 BOE/d (72% horizontal)

The Southern Midland Basin is our largest operating area in terms of production. Following recently completed acquisitions in the first quarter of 2014, we currently have approximately 10,200 net acres in this area. We commenced horizontal drilling efforts at our East Bloxom field in 2012 and have expanded our efforts to two additional fields in the Southern Midland Basin using pad development. Our horizontal wells are currently producing from three zones of the Wolfcamp shale (Upper Wolfcamp B, Lower Wolfcamp B and Wolfcamp A). We plan to continue focusing on these intervals across our entire position in the Southern Midland Basin in 2014 and expect to test additional zones in future years.

Central Midland Basin

- Counties (fields): Midland (Carpe Diem and Pecan Acres) and Ector (Kayleigh)
- 3,359 net acres as of December 31, 2013
- 50 producing vertical wells
- Initiated horizontal development in 2013
- 4th quarter 2013 net production: 564 BOE/d

The Central Midland Basin has been the focus of our high-graded vertical drilling program, targeting multiple zones down to the Woodford shale. We have recently shifted our focus to horizontal development of the Carpe Diem field. Our first Wolfcamp B wells were placed on production in the first quarter of 2014 and we plan to add Carpe Diem to our core development fields going forward. This area is prospective for multiple horizontal development zones and we plan to target the Lower Spraberry in 2014 as we delineate zones outside of the Wolfcamp B.

Northern Midland Basin

- Counties (fields): Borden (Black Magic and Baird Ranch) and Lynn (Tahoka Prospect)
- 19,566 net acres as of December 31, 2013
- One producing vertical well
- Ongoing going exploration and delineation activity

Our Northern Midland Basin position was established in 2012 with the acquisition of 21,617 net acres in Borden and Lynn Counties. We currently own approximately 17,433 net acres following our decision to allow certain acreage in the Northern Midland Basin to expire as we refine our targeted areas for exploration. We began our exploration program in Borden County during the second half of 2012, drilling one gross (0.75 net) vertical and two gross (1.5

net) horizontal wells, targeting the Cline and Mississippi lime. We have subsequently focused our exploration activity on the Mississippi chat, drilling a vertical well (Lacey Newton 2801) in late 2013. We plan to further evaluate the areal extent of this prospective play with at least one vertical exploration well in Borden County in 2014. We also plan to drill our first exploration well in Lynn County in the first half of 2014, testing several prospective zones, including the Spraberry.

For additional details regarding our Permian wells and related information, please see "Present Activities and Productive Wells" included below within this Item.

Other Property

We own a leasehold in approximately 65,000 net acres located in various counties in Nevada. These leases are with the Bureau of Land Management and carry a primary term that expires in 2018. We are evaluating this acreage in conjunction with a third-party consultant and developing options for future activity. Callon does not have any drilling commitments related to this acreage during the primary term.

Proved Reserves

Estimates of volumes of proved reserves at year-end, net to our interest, are presented in MBbls for oil and in MMcf for natural gas, including NGLs, at a pressure base of 15.025 pounds per square inch. Total equivalent volumes are presented in BOE. For the BOE computation, 6,000 cubic feet of gas are the equivalent of one barrel of oil. The ratio of six Mcf of gas to one BOE is typically used in the oil and gas business and represents the approximate energy equivalent of a barrel of oil and an Mcf of natural gas. The price of a barrel of oil is much higher than the price of six Mcf of natural gas, so the ratio of six Mcf to one BOE does not reflect the economic equivalent of a barrel of oil to six Mcf of gas.

The following table sets forth certain information about our estimated net proved reserves. All of our proved reserves are currently located in the continental United States and also included volumes in federal and state waters in the Gulf of Mexico at year-end 2011 and 2012.

	Years Ended December 31,		
	2013	2012	2011
Proved developed:			
Oil (MBbls)	5,960	4,955	5,069
Natural gas (MMcf)	9,059	10,680	11,605
MBOE	7,470	6,735	7,003
Proved undeveloped:			
Oil (MBbls)	5,938	5,825	5,006
Natural gas (MMcf)	8,692	9,073	23,513
MBOE	7,387	7,337	8,925
Total proved:			
Oil (MBbls)	11,898	10,780	10,075
Natural gas (MMcf)	17,751	19,753	35,118
MBOE	14,857	14,072	15,928
Financial Information:			
Estimated pre-tax future net cash flows (a)	$680,627	$592,424	$568,798
Pre-tax discounted present value (a) (b)	$301,144	$250,097	$309,890
Standardized measure of discounted future net cash flows (a) (b)	$283,946	$231,148	$270,357

(a) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2013, in accordance with accounting for asset retirement obligations rules.

(b) The Company uses the financial measure “Pre-tax discounted present value” which is a non-GAAP financial measure. The Company believes that Pre-tax discounted present value, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total standardized measure calculated in accordance with the guidance issued by the FASB for disclosures about oil and gas producing activities for our proved reserves as of December 31, 2013 was $283.9 million inclusive of the $17.2 million discounted estimated future income taxes relating to such future net revenues. The natural gas Mcf prices of $5.45 used in the 2013 reserve estimates have been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected oil prices of $92.16 used in the 2013 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.

See Note 12 of our Consolidated Financial Statements for the additional information regarding the Company's reserves including its estimates of proved reserves, PDPs, PUDs and the Company's estimates of future net cash flows and discounted future net cash flows from proved reserves.

The Company's estimated net proved reserves increased 6% to 14,857 MBOE from 14,072 MBOE at December 31, 2013 and 2012, respectively. Additions during the year were 9,979 MBOE, primarily due to the Company's horizontal development of a portion of its Permian Basin properties. These increases were partially offset by (1) 4,057 MBOE related to the sale of the Company's Gulf of Mexico assets and Haynesville field, (2) 3,724 MBOE of reductions in the Company's PUD reserves, primarily related to the reclassification of certain vertical PUD locations to the horizontal probable category, and a small amount to the horizontal PDP and PUD categories at year end and (3) 1,413 MBOE related to the Company's production during 2013. 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. The vast majority of these previously booked vertical PUDs are now internally classified as horizontal probable reserves, with a small amount now captured in horizontal PDPs and PUDs.

Proved Undeveloped Reserves (PUDs)

Annually, the Company reviews its PUDs to ensure appropriate plans exist for development. PUD reserves are recorded only if the Company has plans to convert these reserves into PDPs within five years of the date they are first recorded. Our development plans include the allocation of capital to projects included within our 2014 capital budget and, in subsequent years, the allocation of capital within our long-range business plan to convert PUDs to PDPs within this five year period. In general, our 2014 capital budget and our long-range capital plans are primarily governed by our expectations of internally generated cash flow and credit facility borrowing availability. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in commodity pricing, oilfield service costs and availability, and other economic factors may lead to changes in development plans.

The following table summarizes the Company's recorded PUDs:

	PUDs (MBOE) at December 31,		
	2013	2012	2011
Permian Basin	7,387	6,040	4,861
Haynesville shale	—	—	1,730
Total Onshore	7,387	6,040	6,591
Medusa (a)	—	1,297	1,186
Habanero (b)	—	—	1,148
Total Offshore	—	1,297	2,334
Total	7,387	7,337	8,925

(a) Effective July 1, 2013, we sold our interest in the Medusa field. See Note 12 for additional information.
(b) Effective December 28, 2012, we sold our interest in the Habanero field. See Note 12 for additional information.

Our PUDs increased 1% to 7,387 MBOE from 7,337 MBOE at December 31, 2013 and 2012, respectively. We added 5,168 MBOE to the Company's PUDs, primarily from the continued horizontal development of our Permian Basin properties. The increase in Permian Basin PUDs was partially offset by the reclassification of 3,724 MBOE, or 51% of volumes included in year-end 2012 PUD reserves related to vertical PUD locations that were moved to the horizontal probable category, and a small amount to the horizontal PDP and PUD categories, as we believe the previously booked Wolfberry PUD locations included certain target zones that we now expect can be more effectively developed over the next five years by our multi-level horizontal drilling program that was commenced during 2012. Also offsetting our PUD additions was 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 our 2012 PUD reserves to PDPs during 2013 from vertical drilling for a net cost of approximately $6 million. Most of our PUDs at year-end 2012 were attributable to vertical well locations. During 2013, our drilling program was predominantly focused on horizontal wells as we continued to delineate our acreage for horizontal development of multiple zones that were previously the target of vertical development wells. Based on our horizontal drilling results and subsequent capital allocation decisions, only three of the vertical wells previously included as PUDs in our 2012 reserve report were drilled in 2013. Our horizontal drilling program converted 4,431 MBOE of reserves that were not classified as proved at year end 2012 to proved developed reserves at year end 2013.

The Company plans to develop its Permian Basin PUDs as part of a multi-year drilling program. At December 31, 2013, we had no reserves that remained undeveloepd for five or more years, and all PUD drilling locations are currently scheduled to be drilled within three to five years of their initial recording.

Table of Contents

Controls Over Reserve Estimates

Compliance as it relates to reporting the Company's reserves is the responsibility of our Senior Vice President of Operations, who has over 35 years of industry experience including 26 years as a manager and is our principal engineer. In addition to his years of experience, our principal engineer holds a degree in petroleum engineering and is experienced in asset evaluation and management.

Callon's controls over reserve estimates included retaining Huddleston & Co., Inc. ("Huddleston"), a Texas registered engineering firm, as our independent petroleum and geological firm. The Company provided to Huddleston information about our oil and gas properties, including production profiles, prices and costs, and Huddleston prepared its own estimates of the reserves attributable to the Company's properties. All of the information regarding reserves in this annual report is derived from Huddleston's report. Huddleston's reserve report letter is included as an Exhibit to this annual report. The principal engineer at Huddleston who is responsible for preparing the Company's reserve estimates has over 30 years of experience in the oil and gas industry and is a Texas Licensed Professional Engineer. Further professional qualifications include a degree in petroleum engineering.

To further enhance the control environment over the reserve estimation process, our Board of Directors includes a Strategic Planning Committee whose purpose, as stated in the Committee's charter, includes assisting management and the Board with its oversight of the integrity of the determination of the Company's oil and natural gas reserves and the work of Huddleston. The Committee's charter also specifies that the Committee shall perform, in consultation with the Company's management and senior reserves and reservoir engineering personnel, the following responsibilities:

- Oversee the appointment, qualification, independence, compensation and retention of the independent petroleum and geological firm (the "Firm") engaged by the Company (including resolution of material disagreements between management and the Firm regarding reserve determination) for the purpose of preparing or issuing an annual reserve report. The Committee shall review any proposed changes in the appointment of the Firm, determine the reasons for such proposal, and whether there have been any disputes between the Firm and management.

- Review the Company's significant reserves engineering principles and policies and any material changes thereto, and any proposed changes in reserves engineering standards and principles which have, or may have, a material impact on the Company's reserves disclosure.

- Review with management and the Firm the proved reserves of the Company, and, if appropriate, the probable reserves, possible reserves and the total reserves of the Company, including: (i) reviewing significant changes from prior period reports; (ii) reviewing key assumptions used or relied upon by the Firm; (iii) evaluating the quality of the reserve estimates prepared by both the Firm and the Company relative to the Company's peers in the industry; and (iv) reviewing any material reserves adjustments and significant differences between the Company's and Firm's estimates.

- If the Committee deems it necessary, it shall meet in executive session with management and the Firm to discuss the oil and gas reserve determination process and related public disclosures, and any other matters of concern in respect of the evaluation of the reserves.

During our last fiscal year, we filed no reports with other federal agencies which contain an estimate of total proved net oil and natural gas reserves.

Production Volumes, Average Sales Prices and Operating Costs

The following table sets forth certain information regarding the production volumes and average sales prices received for, and average production costs associated with, the Company's sale of oil and natural gas for the periods indicated.

	Years Ended December 31,		
	2013	2012	2011
	(in thousands, except per unit data)		
Production			
Oil (MBbls)	911	977	996
Natural gas (Mcf)	3,011	3,588	5,081
Total (MBOE)	1,413	1,575	1,843
Revenues			
Oil sales	$88,960	$96,584	$100,962
Natural gas sales	13,609	14,149	26,682
Total revenues	$102,569	$110,733	$127,644
Operating costs			
Lease operating expense	$19,779	$23,330	$18,285
Production taxes	4,133	3,224	2,062
Total operating costs	$23,912	$26,554	$20,347
Realized prices			
Oil ($/Bbl, including realized gains (losses) on derivatives) (a)	$97.65	$98.86	$101.34
Oil ($/Bbl, excluding realized gains (losses) on derivatives) (a)	97.65	97.41	101.72
Natural gas ($/Mcf, including realized gains (losses) on derivatives) (b)	4.52	3.94	5.25
Natural gas ($/Mcf, excluding realized gains (losses) on derivatives) (b)	4.52	3.94	5.25
Operating costs per BOE			
Lease operating expense	$14.00	$14.81	$9.92
Production taxes	2.92	2.05	1.12
Total operating costs per BOE	$16.92	$16.86	$11.04

(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) 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.

Present Activities and Productive Wells

The following table sets forth the wells drilled and completed during the periods indicated. All such wells were drilled in the continental United States. At December 31, 2013, the Company had four wells awaiting fracture stimulation.

	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.

The following table sets forth the Company's drilled and completed wells, none of which were natural gas or nonproductive for the periods reflected:

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Oil						
Development	25	21.2	14	9.7	36	32.8
Exploratory	1	1.0	7	6.2	—	—
Total	26	22.2	21	15.9	36	32.8

Wells drilled within the productive boundaries of statistical plays, such as on our Southern Midland Basin acreage, have been classified as development wells.

The following table sets forth productive wells as of December 31, 2013:

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	128	107.7	—	—
Royalty interest	3	0.1	—	—
Total	131	107.8	—	—

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas reserves on a Mcfe basis. However, most of our wells produce both oil and natural gas.

14

For the periods presented, the following table sets forth by major field(s) net production volumes and estimated proved reserves:

	Year ended December 31, Production Volumes (MBOE)			% of Total Proved Reserves		
	2013	2012	2011	2013	2012	2011
Onshore						
Permian Basin						
Southern Midland Basin	612	402	254	85 %	51 %	31 %
Central Midland Basin	193	189	99	14 %	16 %	17 %
Northern Midland Basin	8	—	—	1 %	— %	— %
Total Permian Basin	813	591	353	100 %	67 %	48 %
Haynesville shale	18	46	101	— %	1 %	13 %
Total onshore	831	637	454	100 %	68 %	61 %
Offshore						
Medusa	302	464	641	— %	28 %	27 %
Habanero	—	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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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;
-

- 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.

Table of Contents

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.

Table of Contents

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
-

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

Table of Contents

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

- 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

Table of Contents

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.

Table of Contents

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

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.

	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:

	2013	2012	Change	% Change	2011	Change	% Change
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 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.

Table of Contents

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