NEWFIELD EXPLORATION CO /DE/
Form 10-K
February 28, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the fiscal year ended December 31, 2013
or	
¨	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the transition period from to .

Commission file number: 1-12534
Newfield Exploration Company
(Exact name of registrant as specified in its charter)

Delaware (State of incorporation)	72-1133047 (I.R.S. Employer Identification No.)
4 Waterway Square Place, Suite 100, The Woodlands, Texas (Address of principal executive offices)	77380 (Zip Code)

Registrant's telephone number, including area code:
(281) 210-5100
Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $3.2 billion as of June 30, 2013 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 24, 2014, there were 136,316,871 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Portions of the Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 9, 2014, which is incorporated by reference to the extent specified in Part III of this Form 10-K.

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If you are not familiar with any of the oil and gas terms used in this report, we have provided explanations of many of them under the caption "Commonly Used Oil and Gas Terms" at the end of Items 1 and 2 of this report. Unless the context otherwise requires, all references in this report to "Newfield," "we," "us," "our" or the "Company" are to Newfield Exploration Company and its subsidiaries. Unless otherwise noted, all information in this report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates we prepared and are net to our interest.

Forward-Looking Information

This report contains "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 (Exchange Act). All statements, other than statements of historical facts included in this report, are forward-looking, including information relating to anticipated future events or results, such as planned capital expenditures, the availability and sources of capital resources to fund capital expenditures and other plans and objectives for future operations. Forward-looking statements are typically identified by use of terms such as "may," "believe," "expect," "anticipate," "intend," "estimate," "proje "target," "goal," "plan," "should," "will," "predict," "potential" and similar expressions that convey the uncertainty of future ev or outcomes. Although we believe that these expectations are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, including:

- oil, liquids and natural gas prices and demand;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations, including those related to hydraulic fracturing, financial and commodity derivatives and climate change;
- land, legal and ownership complexities inherent in the U.S. oil and gas industry;
- the impact of regulatory approvals;
- the availability and volatility of the securities, capital or credit markets and the cost of capital to fund our operations and business strategies;
- the ability and willingness of current or potential lenders, hedging contract counterparties, customers and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us;
- the prices and quantities of commodities reflected in our commodity hedging arrangements as compared to the actual prices or quantities of commodities we produce or use;
- the volatility and liquidity in the commodity futures and commodity and financial derivatives markets;
- the availability of storage, transportation and refining capacity for the crude oil we produce in the Uinta Basin;
- drilling risks and results;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- global events that may impact our domestic and international operating contracts, markets and prices;
- labor conditions;
- weather conditions;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- competitive conditions;

•terrorism or civil or political unrest in a region or country;
•our ability to monetize non-strategic assets, pay debt and the impact of changes in our investment ratings;
•electronic, cyber or physical security breaches;
•changes in tax rates;
•inflation rates;
•financial counterparty risk;
•uncertainties and changes in estimates of reserves;
•the effect of worldwide energy conservation measures;
•the price and availability of, and demand for, competing energy sources;
•the availability (or lack thereof) of acquisition, disposition or combination opportunities; and
•the other factors affecting our business described below under the caption “Risk Factors.”

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. See Items 1 and 2, “Business and Properties,” Item 1A, “Risk Factors,” Item 3, “Legal Proceedings,” Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” for additional information about factors that may affect our businesses and operating results. These factors are not necessarily all of the important factors that could affect us. Use caution and common sense when considering these forward-looking statements. Unless securities laws require us to do so, we do not undertake any obligation to publicly correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

PART I
Items 1 and 2. Business and Properties

General

Newfield Exploration Company, a Delaware corporation formed in 1988, is an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. During 2013, a decision was made to focus on our principal domestic areas of operation, which include the Mid-Continent, the Rocky Mountains and onshore Gulf Coast. During 2013, our international businesses in Malaysia and China were held for sale and reported as "discontinued operations." In early February 2014, we closed the sale of our Malaysian business for approximately $898 million. We are still in the process of selling our offshore China business.

Through our website, www.newfield.com, you can access, free of charge, electronic copies of our governing documents, including our Board of Directors' Corporate Governance Principles and the charters of the committees of our Board of Directors. In addition, you can access through our website the documents we file with the U.S. Securities and Exchange Commission (SEC), including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K as soon as reasonably practicable after we file or furnish them. You also may request printed copies of our SEC filings or governance documents, free of charge, by writing to our corporate secretary at the address on the cover of this report. Information contained on our website is not incorporated herein by reference and should not be considered part of this report.

In addition, the public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Our Business Strategy

In 2013, we celebrated our 25th year as a company. We have adapted our focus areas and business strategies through the years to effectively compete within our industry and remain profitable. Today, our overarching business strategy is to deliver long-term stockholder value through safely, ethically and profitably exploring for, acquiring and developing North American oil and gas resource plays. Over the last five years, we have refined our asset base and focused on creating value through liquids investments. Today, we have a diversified asset portfolio capable of sustainable growth. Our core strategy consists of the following key elements:

- maintaining a diversified portfolio of core North American assets, with a near-term investment focus on oil and liquids growth;
- maintaining a strong capital structure;
- growing through a combination of development drilling and select acquisitions;
- operating our assets and improving operational efficiencies; and
- attracting and retaining quality employees and ensuring their interests are aligned with our stockholders' interests.

Maintaining a Diversified Portfolio of Core North American Assets. Over the last several years, we have transitioned from a conventional, natural gas company to an unconventional company focused on North American liquids-rich resource plays. By maintaining a diverse asset portfolio, we increase our flexibility to respond, and limit our exposure, to the volatility and unique risks our industry faces, such as geologic risks, geographic risks and commodity price risks. In line with this element of our strategy and the continued weakness in natural gas prices, our 2014 plans include:

- allocating substantially all of our planned $1.6 billion in domestic capital investments to our liquids-rich assets; and
- limiting investments in natural gas, accepting natural field declines in our natural gas assets and preserving future opportunities in our major held-by-production natural gas assets.

Maintaining a Strong Capital Structure. Maintaining a strong capital structure is central to our strategy. A strong balance sheet preserves financial flexibility and helps ensure that we maintain sufficient liquidity to implement our overall business strategy. In line with this element of our strategy, our 2014 plans include:

- restoring the available capacity under our revolving credit facility to $1.4 billion by utilizing proceeds from the sale of our Malaysian business, which closed in February 2014;
- continuing the process of selling our China business, and using the expected proceeds to fund our domestic capital investment plans; and
- using derivative markets to hedge a portion of our future production to manage commodity price risk and to help ensure adequate funds to execute our drilling programs.

Growing Through a Combination of Development Drilling and Select Acquisitions. Throughout our 25-year history, our growth has come from a combination of select acquisitions and exploration and exploitation drilling. We develop resources in our focus areas while continually looking for new opportunities in and around these areas. To manage risks associated with our strategy to grow reserves through drilling, substantially all of the domestic wells we drilled in 2013 had low geologic risk. Since 2000, we have completed several acquisitions that led to the expansion of our operating areas or the establishment of focus areas onshore in the United States. In 2013, we acquired about 65,000 net acres in Oklahoma's Anadarko Basin "STACK" play. This recent acquisition complemented our growing position in the basin's prolific Cana Woodford play, which was largely leased in 2011 and 2012. In 2011, we acquired approximately 65,000 net acres in the Uinta Basin, which fit well with our existing properties in the basin. We are focused on distinct geographic regions and geologic plays where we can leverage our experience and core competencies. In line with these elements of our strategy, our 2014 plans include:

- delivering approximately 30% year-over-year domestic liquids growth by focusing on developing our fields in the Anadarko, Uinta, Williston and Maverick basins; and
- continuing to consider select acquisition opportunities aligned with our strategy and asset base.

Operating our Assets and Improving Operational Efficiencies. We prefer to operate our properties. By controlling operations, we can better manage the timing of their development and production, control operating expenses and capital investments, ensure the appropriate application of technologies and promote safety and corporate responsibility. We operate a significant portion of our total net production and believe that improving operational efficiencies requires extensive knowledge of the geologic and operating conditions in the areas where we operate. Therefore, we focus our efforts on a limited number of geographic areas where our core competencies provide a competitive advantage and can positively influence operational efficiencies. Geographic focus allows for the more efficient use of both our capital and human resources. In line with this element of our strategy, our 2014 plans include:

- improving operational efficiencies by focusing on unconventional resource plays that have large acreage positions and deep inventories of lower-risk drilling locations — in development, these plays lend themselves to efficiency gains in drilling and completion operations and provide sustainable growth profiles;
- increasing corporate responsibility awareness and encouraging all of our people to maintain safe operations, minimize environmental impact and conduct their daily business with the highest of ethical standards; and
- ensuring that the right people are deployed on the right projects.

Attracting and Retaining Quality Employees and Ensuring Their Interests are Aligned with our Stockholders' Interests. We believe in hiring top-tier talent and are committed to our employees' education and development. We believe that employees should be rewarded for their performance and that their interests should be aligned with our stockholders' interests. As a result, we reward and encourage our employees through performance-based compensation and equity-based ownership.

2014 Outlook and Planned Capital Investments

Our strategy is to focus on North American resource plays, and we plan to invest $1.6 billion (excluding capitalized internal costs) to these activities in 2014. In early February 2014, we closed the sale of our Malaysian business for approximately $898 million and are continuing to take steps to sell our offshore China business. Depending on the timing of the sale for our China business, we intend to invest approximately $100 million in China in 2014. Our 2014 investments will be financed through our cash flows from operations, proceeds from our recent Malaysian sale and the use of our credit facility.

Our domestic liquids production is expected to grow approximately 30% in 2014. As a result of reduced investments over the last several years, our natural gas assets have experienced natural declines. In 2014, we expect our gas volumes to be consistent with the prior year. Combined, we expect our 2014 production from continuing operations to range from 44 – 48 MMBOE, or about 16% higher than 2013 domestic volumes.

Approximately 89% of our expected 2014 domestic oil and gas production is hedged against future changes in commodity prices. For a complete discussion of our hedging activities, a list of open contracts as of December 31, 2013 and the estimated fair value of those contracts as of that date, see Note 5, "Derivative Financial Instruments," to our consolidated financial statements.

Our Properties and Plans for 2014

Our strategic focus is on North American resource plays. Our domestic plays represent approximately 94% of our proved reserves at year-end 2013.

Mid-Continent. Approximately 45% of our proved reserves are located in our Mid-Continent region. We have more than a decade of experience developing the Woodford Shale. Our acreage includes more than 400,000 net acres in the region, which includes positions in the dry gas Arkoma Basin Woodford and the liquids-rich Cana Woodford in the Anadarko Basin. Our position in the Anadarko Basin was assembled over the last three years.

Anadarko Basin. We have about 225,000 net acres that are prospective for development in the Anadarko Basin. As of February 2014, we had drilled approximately 75 wells in the Anadarko Basin, with wells yielding high volumes of oil and natural gas liquids. For 2014, we have allocated approximately $700 million, or double our previous year's investment, to drilling in our SCOOP (located in South Central Oklahoma) and STACK plays in the Anadarko Basin. We are planning to operate eight rigs throughout the year. At year-end 2013, our production was approximately 25,000 BOEPD, consisting of 6,600 BOPD, 7,050 BOEPD of NGLs and 67 MMcf/d.

Arkoma Basin. We have significant dry gas production from the Arkoma Basin. The area represents approximately 20% of our total consolidated proved reserves. Our investment levels in this area have been significantly curtailed over the last four years due to low natural gas prices. As of December 31, 2013, we had approximately 150,000 net acres in the Arkoma Basin and our net production was approximately 21,700 BOEPD, consisting of 140 BOPD, 190 BOEPD of NGLs and 128 MMcf/d. Our production in this area is on natural decline. Substantially all of our acreage in this region is held-by-production.

Granite Wash. We have approximately 45,000 net acres prospective for development in the Granite Wash, located in the Anadarko Basin of northern Texas and western Oklahoma. Our largest producing field in the Granite Wash is Stiles/Britt Ranch. At year-end 2013, our net production from the area was approximately 13,300 BOEPD, consisting of 1,400 BOPD, 3,700 BOEPD of NGLs and 49 MMcf/d.

Rocky Mountains. We are actively assessing and developing more than 300,000 net acres in the Rocky Mountain region. Our assets are primarily oil and characterized by long-lived production. Our 2014 efforts are focused primarily in the Uinta and Williston basins.

Uinta Basin. About 26% of our proved reserves are located in the Uinta Basin. We have approximately 225,000 net acres in the Uinta Basin, and our operations can be divided into two areas: the Greater Monument Butte Unit (GMBU) waterflood and an area to the north and adjacent to the GMBU that we refer to as the Central Basin.

We entered the Uinta Basin through a 2004 acquisition of the Greater Monument Butte Unit, a large waterflood field. Since that time, we have drilled approximately 1,700 wells in the unit and today have approximately 1,300 productive oil wells and approximately 1,100 water injection wells. The primary producing horizon in the unit is the

Green River. Through an acquisition in 2011, we expanded our footprint in the area and today have more than 140,000 prospective net acres outside the GMBU. We have been exploring deeper geologic horizons on this acreage, including the Uteland Butte and Wasatch formations.

We have allocated approximately $400 million to our Uinta Basin programs in 2014, of which nearly half is expected to be allocated to the Central Basin. Our net production from the Uinta Basin at year-end 2013 was approximately 24,250 BOEPD, comprised of 19,200 BOPD, 950 BOEPD of NGLs and 25 MMcf/d. To date, we have drilled approximately 80 wells in these plays and plan to drill approximately 15 wells to test the Uteland Butte and Wasatch formations in 2014. Our 2014 production in the Uinta Basin is expected to increase about 5% over 2013 levels.

Williston Basin. We have approximately 100,000 net acres in the Williston Basin, of which 41,000 acres are being actively developed in the Bakken and Three Forks plays of North Dakota. Our activities today are largely development focused and we are drilling multi-well pads with lateral lengths as long as 10,000 feet. Our net production at year-end 2013 was approximately 13,600 BOEPD, comprised of 10,500 BOPD, 1,300 BOEPD of NGLs and 11 MMcf/d. We have allocated approximately $330 million to our Williston Basin developments and plan to operate four rigs throughout the year, which is consistent with our 2013 activity levels. We expect our production from the Williston Basin to increase about 40% over 2013 levels.

Onshore Gulf Coast. We have approximately 160,000 net acres in the Maverick Basin, of which we believe approximately 25,000 net acres are prospective for development. Our acreage is located primarily in the Maverick Basin of Maverick, Dimmit and Zavala counties, Texas. To date, we have completed more than 100 wells in the basin. We expect to operate one rig in the area in 2014 to drill about 20 wells. Our development is focused on pad drilling with lateral lengths of at least 7,500 feet. Our planned capital investments for 2014 are approximately $170 million. At year-end 2013, our net daily production in the Eagle Ford was approximately 11,800 BOEPD, consisting of 6,800 BOPD, 2,600 BOEPD of NGLs and 15 MMcf/d, and production is expected to grow 30% over 2013 levels.

Over the last several years, we have slowed our activities in many of our conventional natural gas plays and sold certain non-strategic assets. The proceeds from these asset sales have been invested in our unconventional resource plays. As of December 31, 2013, we owned an interest in approximately 109,000 net acres in conventional onshore plays. At year-end 2013, our net production was approximately 6,800 BOEPD, consisting of 360 BOPD, 300 BOEPD of NGLs and 37 MMcf/d, from our conventional onshore Texas assets. We expect our production in these conventional plays to continue to experience natural declines in 2014 due to limited investment.

Reserves

At year-end 2013, we had proved reserves from continuing operations of 576 MMBOE, 8% higher than year-end 2012. Proved reserves at year-end 2013 associated with discontinued operations were 36 MMBOE, 4% higher than year-end 2012. Highlights from our year-end 2013 proved reserves report include:

- continuing operations (domestic) liquids reserves increased 26% over 2012 and represent 52% of domestic proved reserves;
- domestic proved developed reserves increased 15% over 2012;
- 56% of domestic reserves are proved developed;
- domestic reserves account for 94% of our total proved reserves; and
- our domestic proved reserve life index is approximately 14 years (or approximately 13 years including reserves from discontinued operations).

The table below summarizes our proved reserves by area at December 31, 2013.

	Proved Reserves (In MMBOE)	Percentage of Proved Reserves	
Continuing operations:			
Onshore Gulf Coast	51	8	%
Mid-Continent	275	45	%
Rocky Mountains	250	41	%
Total continuing operations	576	94	%
Discontinued operations:			
International	36	6	%
Total	612	100	%

Concentration

Reserves Concentration. The table below sets forth the concentration of our proved reserves attributable to our largest fields. Our largest fields by volume, the Greater Monument Butte Unit, Arkoma Woodford Shale and SCOOP, accounted for about 47% of the total net present value of our proved reserves at December 31, 2013.

	Percentage of Proved Reserves
10 largest fields	90%
3 largest fields	58%

Largest Fields. The table below sets forth the annual production volumes, average realized prices and related production cost structure on a per unit-of-production basis for our largest fields (those whose reserves are greater than 15% of our total proved reserves), which are the GMBU, Arkoma Woodford Shale and SCOOP. For a discussion regarding our total domestic and international annual production volumes, average realized prices, related cost structure and information about delivery commitments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," which disclosure is incorporated herein by reference.

	Year Ended December 31,		
	2013	2012	2011
Production:			
Crude oil and condensate (MBbls)			
Greater Monument Butte Unit	3,764	3,720	3,297
Arkoma Woodford Shale	65	130	107
SCOOP	1,323	379	181
Natural gas (Bcf)			
Greater Monument Butte Unit	0.5	1.9	1.9
Arkoma Woodford Shale	51.7	63.2	69.4
SCOOP	16.8	5.1	2.5
NGLs (MBbls)			
Greater Monument Butte Unit	152	133	118
Arkoma Woodford Shale	75	86	110
SCOOP	1,888	653	337
Average Realized Prices:			
Crude oil and condensate (per Bbl)			
Greater Monument Butte Unit	$78.24	$77.58	$78.19
Arkoma Woodford Shale	$93.71	$90.54	$88.80
SCOOP	$93.75	$86.03	$87.47
Natural gas (per Mcf)			
Greater Monument Butte Unit	$4.74	$1.71	$3.15
Arkoma Woodford Shale	$3.31	$2.35	$3.57
SCOOP	$3.35	$2.33	$3.28
NGLs (per Bbl)			
Greater Monument Butte Unit	$52.26	$63.92	$73.90
Arkoma Woodford Shale	$20.62	$27.64	$33.81
SCOOP	$31.62	$25.16	$33.44
Average Production Cost:			
Greater Monument Butte Unit (per BOE)	$24.14	$16.48	$14.45
Arkoma Woodford Shale (per Mcfe)	$2.10	$1.80	$1.58
SCOOP (per BOE)	$4.38	$4.59	$5.28

Estimated Reserves

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates is completed in accordance with our prescribed internal control procedures, which include verification of data input into our reserves forecasting and economics evaluation software, as well as multi-discipline management reviews, as described below. The technical employee responsible for overseeing the preparation of the reserves estimates has a Bachelor of Science in Petroleum Engineering, with more than 30 years of experience (including 20 years of experience in reserve estimation).

Our reserves estimates are made using available geological and reservoir data as well as production performance data. These estimates, made by our petroleum engineering staff, are reviewed annually with management and revised, either upward or downward, as warranted by additional data. The data reviewed includes, among other things, seismic data, well logs, production tests, reservoir pressures, and individual well and field performance data. The data incorporated into our interpretations includes structure and isopach maps, individual well and field performance and other engineering and geological work products such as material balance calculations and reservoir simulation to arrive at conclusions about individual well and field projections. Additionally, offset performance data, operating expenses, capital costs and product prices factor into estimating quantities of reserves. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental regulations, as well as changes in the expected recovery rates associated with infill drilling. Sustained decreases in prices, for example, may cause a reduction in some reserves due to reaching economic limits sooner.

Actual quantities of reserves recovered will most likely vary from the estimates set forth below. Reserves and cash flow estimates rely on interpretations of data and require assumptions that may be inaccurate. For a discussion of these interpretations and assumptions, see “Actual quantities of oil, gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates” under Item 1A, “Risk Factors,” of this report. Our estimates of proved reserves, proved developed reserves and proved undeveloped reserves and future net cash flows and discounted future net cash flows from proved reserves at December 31, 2013, 2012 and 2011, as well as changes in proved reserves during the last three years, are contained in “Supplementary Financial Information — Supplementary Oil and Gas Disclosures” in Item 8 of this report.

The following table shows by country and in the aggregate a summary of our proved oil and gas reserves as of December 31, 2013.

	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBOE)
Proved Developed Reserves:				
Domestic	112	1,055	35	322
International:[1]				
Malaysia[2]	11	—	—	11
China	4	—	—	4
Total International	15	—	—	15
Total Proved Developed	127	1,055	35	337
Proved Undeveloped Reserves:				
Domestic	122	593	33	254
International:[1]				
Malaysia[2]	—	—	—	—
China	21	—	—	21
Total International	21	—	—	21
Total Proved Undeveloped	143	593	33	275
Total Proved Reserves	270	1,648	68	612

(1) Classified as discontinued operations.
(2) Sold February 2014.

Proved Reserves. Our year-end 2013 proved reserves of 612 MMBOE increased 8% compared to our proved reserves at year-end 2012. Our reserves consisted of 282 MMBOE proved developed producing, 55 MMBOE proved developed non-producing and 275 MMBOE proved undeveloped reserves. Our proved liquids reserves at year-end 2013 were 338 million barrels, compared to 274 million barrels at year-end 2012, an increase of 23%. During 2013, oil and condensate reserves increased 33 million barrels and NGL reserves increased 31 million barrels. At year-end 2013, 80% of our proved liquids reserves were crude oil or condensate. At December 31, 2013, our proved natural gas reserves were 1,648 Bcf which represented a decrease of 6% compared to 2012.

During 2013, we added 80 MMBOE through discoveries, extensions and other additions. Consistent with our continued focus on domestic liquids, our 2013 additions were 98% domestic and 61% were liquids, which was 27 million barrels of oil and 22 million barrels of NGLs. Through infill drilling revisions, we added 75 MMBOE. At December 31, 2013, the SEC pricing for natural gas was $3.67 per MMBtu, a 33% increase compared to the prior year-end. As a result, we revised our total proved reserves upward by 10 MMBOE. However, consistent with our domestic liquids focus we removed 294 Bcf of natural gas reserves because we do not expect to drill them within the next five years. During 2013, we had a negative 24 MMBOE performance revision, 90% of the revision was in natural gas and primarily associated with the Uinta Basin.

Proved Undeveloped Reserves. Our proved undeveloped reserves at December 31, 2013 were 275 MMBOE compared to 268 MMBOE at December 31, 2012. Liquids comprised 64% of our total proved undeveloped reserves as of December 31, 2013. During 2013, we invested approximately $0.7 billion of drilling, completion and facilities-related capital to convert 32 MMBOE of our December 31, 2012 proved undeveloped reserves into proved developed reserves. Additionally, we invested approximately $0.1 billion of facilities-related capital for the continued development of our proved undeveloped reserves that were not fully converted to proved developed status as of December 31, 2013. Through infill drilling revisions, we added 41 MMBOE. During 2013, we added 54 MMBOE of new proved undeveloped reserves through discoveries, extensions and other additions, a 1 MMBOE net increase due to sales and acquisitions, and negative revisions of 62 MMBOE primarily driven by increased focus on liquids delaying the development of 49 MMBOE of gas reserves in the next five years.

Proved undeveloped reserve quantities are limited by the activity level of development drilling we expect to undertake during the 2014-2018 five-year period. Of the 275 MMBOE of proved undeveloped reserves at December 31, 2013, 29 MMBOE is associated with the Greater Monument Butte waterflood and are currently planned to be developed within the next five years, but exceed five years from the date of first booking. The waterflood requires the timely and orderly drilling of production and injection wells, conversion of producing wells to injection wells and the injection of certain amounts of water before all producing wells are drilled to optimize oil recovery and project economics. The scope and scale of this project is such that if it were terminated, for whatever reason, a significant portion of previously invested capital would be lost. For additional information regarding the changes in our proved reserves, see our "Supplementary Oil and Gas Disclosures" under Item 8 of this report.

In the years 2011 through 2013, we developed 19%, 9% and 12%, respectively, of our prior year-end proved undeveloped reserves. The development plans in our year-end reserve report reflect (i) the allocation of capital to projects in the first year of activity based upon the initial budget for such year and (ii) in subsequent years, the capital allocation in our five-year business plan, each of which generally is governed by our expectations for capital investment in such time period. Changes in commodity pricing between the time of preparation of the reserve report and actual investment, investment alternatives that may have been added to our portfolio of assets, changes in the availability and costs of oilfield services, and other economic factors may lead to changes in our development plans. As a result, the future rate at which we develop our proved undeveloped reserves may vary from historical development rates.

Reserves Sensitivities

To determine our year-end 2013 reserve estimates, we utilized SEC pricing for natural gas of $3.67 per MMBtu and crude oil of $96.82 per barrel.

Using crude oil prices of $80 and $90 per barrel, the quantity of our domestic proved developed reserves decreases by 1% and 0% respectively, due to shortening of the economic life. Our proved undeveloped liquids reserves are primarily in the Uinta Basin of Utah, the Williston Basin of North Dakota and the Anadarko Basin of Oklahoma. At crude oil prices of $80 per barrel, and without a commensurate change in cost, our domestic proved undeveloped reserves would decrease by approximately 9 MMBOE, and we would reduce our future capital investment by a total of approximately $250 million during the next five years. As a result of the foregoing, at $80 per barrel our domestic proved reserves would decrease by 2%.

Our planned capital activity focuses on liquids versus natural gas and is limited by the level of development drilling we expect to undertake in the future. At natural gas prices below $3.00 per MMBtu, our domestic proved developed reserves would decrease by 2% due to shortening the economic life. In line with our liquids focus, at the lower gas prices our undeveloped reserves remain materially unchanged. At higher natural gas prices of $4.00 and $5.00 per MMBtu, and without reconfiguring to optimize our development plan, the pre-tax present value of our proved reserves would increase by $223 million and $902 million, respectively.

Under the terms of our production sharing contracts (PSC) in Malaysia and China, an increase or decrease in realized oil prices would result in a decrease or increase, respectively, in our proved reserves. At higher oil prices, lesser quantities of oil are required for cost recovery and at lower oil prices, greater quantities of oil are required for cost recovery. Our share (the contractor's share) of future production is impacted accordingly. The effect of higher or lower oil prices may be partially offset by extending or shortening, respectively, the economic life of proved reserves.

Drilling Activity

The following table sets forth the number of oil and gas wells that completed drilling for each of the last three years.

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Domestic:						
Productive[1]	198	95.2	190	90.5	263	159.2
Nonproductive[2]	1	1.0	2	2.0	2	1.0
International:[3]						
China:						
Nonproductive	1	1.0	—	—	1	1.0
Malaysia:						
Productive[4]	2	1.1	—	—	1	0.7
Nonproductive	—	—	2	0.9	—	—
International Total:						
Productive	2	1.1	—	—	1	0.7
Nonproductive	1	1.0	2	0.9	1	1.0
Exploratory well total	202	98.3	194	93.4	267	161.9
Development wells:						
Domestic:						
Productive	276	217.1	214	170.9	253	199.6
International:[3]						
China:						
Productive	3	0.3	—	—	—	—
Malaysia:						
Productive	12	7.5	12	7.7	17	5.8
International Total:						
Productive	15	7.8	12	7.7	17	5.8
Development well total	291	224.9	226	178.6	270	205.4

(1) Includes 170 gross (78.6 net) wells in 2013, 161 gross (64.2 net) wells in 2012 and 202 gross (121.6 net) wells in 2011 that are exploitation wells.
(2) The 2013 and 2011 wells are exploitation wells.
(3) Classified as discontinued operations.
(4) The 2013 wells are exploitation wells.

We were in the process of drilling 16 gross (13.1 net) development wells domestically at December 31, 2013. Internationally, we were drilling 1 gross (0.4 net) exploitation well in Malaysia at December 31, 2013.

Productive Wells

As of December 31, 2013, we had the following productive oil and gas wells, including 12 gross (5 net) oil wells with multiple completions.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
Domestic:						
Oil	2,513	2,044.1	836	70.0	3,349	2,114.1
Natural gas	1,523	1,218.9	1,313	203.6	2,836	1,422.5
International:[1]						
Offshore China:						
Oil	—	—	41	4.9	41	4.9
Offshore Malaysia:						
Oil	44	27.6	21	10.5	65	38.1
Natural gas	3	1.9	3	1.5	6	3.4
Total International:						
Oil	44	27.6	62	15.4	106	43.0
Natural gas	3	1.9	3	1.5	6	3.4
Total:						
Oil	2,557	2,071.7	898	85.4	3,455	2,157.1
Natural gas	1,526	1,220.8	1,316	205.1	2,842	1,425.9
Total	4,083	3,292.5	2,214	290.5	6,297	3,583.0

(1) Classified as discontinued operations.

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements or production sharing contracts. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. Generally, an operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates established by the various operating agreements or contracts. The charges customarily vary with the depth and location of the well being operated.

Acreage Data

The following two tables list by geographic area interests we owned in developed and undeveloped oil and gas acreage at December 31, 2013, along with a summary by year of our undeveloped acreage scheduled to expire in the next five years. In most cases, the drilling of a commercial well, or the filing and approval of a development plan or suspension of operations will hold the acreage beyond the expiration date. Domestic ownership interests are onshore and generally take the form of “working interests” in oil and gas leases that have varying terms. International ownership interests, which are now classified as discontinued operations, are offshore and generally arise from participation in PSCs.

Total Acreage

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
Domestic:				
Mid-Continent	601	325	259	189
Rocky Mountains	284	196	783	588
Onshore Gulf Coast	310	230	58	39
Total Domestic	1,195	751	1,100	816
International:				
China	34	9	—	—
Malaysia	202	104	3,399	1,234
Total International	236	113	3,399	1,234
Total	1,431	864	4,499	2,050

Expiring Acreage

	Undeveloped Acres Expiring									
	2014		2015		2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
Domestic:										
Mid-Continent	58	22	47	32	63	48	6	5	—	—
Rocky Mountains	44	23	325	276	81	41	70	66	6	6
Onshore Gulf Coast	20	13	15	14	1	—	1	1	—	—
Total Domestic	122	58	387	322	145	89	77	72	6	6
International:										
Offshore Malaysia	1,586	593	1,813	641	—	—	—	—	—	—
Total International	1,586	593	1,813	641	—	—	—	—	—	—
Total	1,708	651	2,200	963	145	89	77	72	6	6

At December 31, 2013, we owned fee mineral interests in 441,827 gross (85,605 net) acres. These interests do not expire.

Title to Properties

We believe that we have satisfactory title to our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes, development obligations under oil and gas leases or capital commitments under PSCs or exploration licenses. As is customary in the industry in the case of undeveloped properties, often limited investigation of record title is made at the time of acquisition. Investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

Marketing

Substantially all of our oil, gas and NGLs are sold at market-based prices to a variety of purchasers, primarily under short-term contracts (less than 12 months). We also have long-term contracts in the Uinta Basin at market-based prices. For a list of purchasers of our production that accounted for 10% or more of our total revenues for the three preceding calendar years, please see Note 1, “Organization and Summary of Significant Accounting Policies — Major

Customers," to our consolidated financial statements in Item 8 of this report, which information is incorporated herein by reference. We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers are readily available with the exception of purchasers of our Uinta Basin oil production.

Due to the paraffin content of our Uinta Basin production, there is limited access to refining capacity outside of the Salt Lake City area at this time. In late 2011 and early 2012, we signed two separate long-term agreements (7 and 10 years, respectively) for a combined 38,000 BOPD of refining capacity in the Salt Lake City, Utah area. These agreements are expected to add approximately 20,000 BOPD of "new" refinery capacity in the region. Specifically, in December 2011, we executed a crude oil supply agreement with Tesoro Corporation to provide 18,000 BOPD of supply capacity at Tesoro's refinery in Salt Lake City, Utah. This agreement, which spans a seven-year period, commenced in mid-2013 and increases to 18,000 BOPD over the next year. In addition, in January 2012, we executed a crude oil supply agreement with HollyFrontier Corporation to provide approximately 20,000 BOPD of supply capacity at HollyFrontier's Woods Cross, Utah refinery. This agreement spans a 10-year period, with limited commitments expected to commence upon the refiner completing the expansion of their facility, which is expected in late 2015, and increases to 20,000 BOPD during the following year. We continue to seek additional capacity to accommodate our growth plans for the Uinta Basin, including the use of rail and pipelines to access new markets outside of the Salt Lake City area. Please see the discussion under "There is limited transportation and refining capacity for our black and yellow wax crude oil, which may limit our ability to sell our current production or to increase our production in the Uinta Basin" in Item 1A of this report.

Competition

Competition in the oil and gas industry is intense, particularly with respect to the hiring and retention of technical personnel, the acquisition of properties and access to drilling rigs and other services. Please see the discussion under "Competition for, or the loss of, our senior management or experienced technical personnel may negatively impact our operations or financial results" and "Competition in the oil and gas industry is intense" in Item 1A of this report, which information is incorporated herein by reference.

Segment Information

Our continuing operations are comprised of a single business segment, the domestic exploration, development and production of oil and natural gas. Prior to classifying our international businesses as held-for-sale and discontinued operations, we reported business segments for Malaysia and China.

Employees

As of February 24, 2014, we had 1,548 employees. All but 68 of our employees were located in the United States. None of our employees are covered by a collective bargaining agreement. We believe that relationships with our employees are satisfactory.

Regulation

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, provincial, tribal, local, foreign and international regulations. An overview of these regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen resource or environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Please see the discussion under the caption "We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business," in Item 1A of this report.

General Overview.   Our oil and gas operations are subject to various federal, state, provincial, tribal, local, foreign and international laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- acquisition of seismic data;
- location of wells;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;

- drilling and casing of wells;
- issuance of permits in connection with exploration, drilling and production;
- well production;
- spill prevention plans;
- protection of private and public surface and ground water supplies;
- emissions reporting, permitting or limitations;
- protection of endangered species and habitat;
- occupational safety and health;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- transportation of production; and
- export of natural gas.

Federal Regulation of Drilling and Production. Many of our domestic oil and gas leases are granted by the federal government and administered by the BSEE, ONRR or the BLM, all federal agencies. BLM leases contain relatively standardized terms and require compliance with detailed BLM, BSEE and ONRR regulations. Many onshore leases contain stipulations limiting activities that may be conducted on the lease. Some stipulations are unique to particular geographic areas and may limit the time during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban surface activity. Under certain circumstances, the BLM or the BSEE, as applicable, may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore in a number of states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, disclosure of hydraulic fracturing fluid composition, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas. The effect of these regulations is to limit the amounts of oil and gas we can produce from our wells and to limit the number of wells or the locations at which we can drill.

Environmental Regulations. We are subject to various federal, state, provincial, tribal, local, foreign and international laws and regulations concerning occupational safety and health, oil and gas production, as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to, among other things:

- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials;
- the emission of certain gases or materials into the atmosphere;
- the monitoring, abandonment, reclamation and remediation of wells and other sites, including sites of former operations;

- various environmental reporting and permitting requirements;
- the development of emergency response and spill contingency plans; and
- protection of private and public surface and ground water supplies.

We consider the costs of environmental regulatory compliance and protection and safety and health compliance necessary and manageable parts of our business. We have been able to plan for and comply with environmental regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increased stringency, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and will likely continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters and the cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted or banned by governmental authorities. Moreover, some environmental laws and regulations may impose strict liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent future laws or regulations are implemented or other governmental action is taken that prohibits, restricts or materially increases the costs of onshore or offshore drilling, or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected.

Discharges to waters of the U.S. are further regulated and limited under the federal Clean Water Act, or CWA, and analogous state and tribal laws. The CWA prohibits any discharge of pollutants into waters of the United States except in compliance with permits issued by federal and state governmental agencies. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. The CWA also requires the preparation of oil spill response plans and spill prevention, control and countermeasure or “SPCC” plans. We have such plans in place and have made changes as necessary due to changes by the U.S. Environmental Protection Agency, also known as the “EPA,” that became effective in November 2009.

The National Environmental Policy Act, or NEPA, requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. This regulation can lead to additional costs and delays in permitting for operators as the BLM may need to prepare additional Environmental Assessments and more detailed Environmental Impact Statements, which would be available for public review and comment.

The Endangered Species Act restricts activities that may affect federally-identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal or permanent ban on operations in affected areas. Similarly, the Migratory Bird Treaty Act, or MBTA, implements various treaties and conventions between the U.S. and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas.

The Resource Conservation and Recovery Act, or RCRA, generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste “drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy,” the EPA and state agencies may regulate these wastes as solid wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the “Superfund” law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a “hazardous substance” into the environment. Such “responsible parties” may be subject to joint and several liability under the Superfund law for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease onshore properties that have been used for the exploration and production of oil and gas for a number of years. Many of these onshore properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and any wastes that may have been disposed or released on them may be subject to the Superfund law, RCRA and analogous state laws and common law obligations, and we potentially could be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

The Clean Air Act, or CAA, and comparable state statutes regulate and limit the emission of air pollutants by the Company and affect both our onshore and offshore oil and gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed and continues to develop more stringent regulations governing emissions of toxic air pollutants, and is considering the expanded regulation of existing air pollutants and additional air pollutants. In addition, the EPA has recently promulgated regulations that are designed to reduce the emission of volatile organic chemicals (VOCs) and that will require oil and gas companies by 2015 to utilize “green completions” to capture VOCs and other air pollutants when wells are fracked. Such regulations may increase the costs of compliance for some facilities or the market price for oil and gas commodities.

The Occupational Safety and Health Act, or OSHA, and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

For more than a decade, Congress has been considering a variety of sectoral or economy-wide market-based tax, energy or environmental mechanisms to regulate or induce the reduction of emissions of greenhouse gases by several commercial or industrial sectors. In June of 2009, the U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009. In addition, more than one-third of the states have implemented some form of legal measure to regulate or reduce emissions of greenhouse gases. On April 2, 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an “air pollutant” under the CAA. On December 7, 2009, the EPA responded to the Massachusetts, et al. v. EPA decision with an “endangerment finding” for greenhouse gases emitted from certain mobile sources. The EPA finding concluded that such GHG emissions “cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare” and contribute to the threat of climate change.

In 2013, the United States Court of Appeals for the District of Columbia Circuit upheld, in Coalition for Responsible Regulation, Inc. v. EPA, the EPA endangerment finding. On October 15, 2013, the United States Supreme Court declined to review the EPA’s endangerment finding or its underlying scientific conclusions, as well as the regulations governing emissions of GHGs from motor vehicles, but granted review on several stationary source permitting issues under the CAA. By leaving the endangerment finding undisturbed, the Court has effectively affirmed the EPA’s authority to regulate GHGs under the CAA.

In June 2013, President Obama released a Climate Action Plan which sets forth a series of executive actions the current administration intends to undertake to address climate change. The Climate Action Plan includes a two-part directive that the EPA promulgate rules to regulate GHG emissions from new and existing fossil fuel power plants on a defined schedule and consider employing market-based mechanisms. Specifically, the President issued a Presidential Memorandum directing the EPA to propose and timely finalize carbon emission standards for certain new fossil fuel power plants under Section 111(b) of the CAA, and to propose carbon emission “standards, regulations or guidelines” for existing fossil fuel power plants under Section 111(d) of the CAA by June 1, 2014.

Several other federal agencies and state governments are considering or have already implemented rules to regulate, monitor, or induce market reductions of GHG emissions. It is not possible at this time, however, to predict the applicability or stringency of future GHG mitigation regulations for the oil and gas industry, if at all, or how any new legislation or regulations would impact our business. Any such future federal laws and regulations could affect oil and natural gas commodity market pricing, and result in increased costs of compliance, or additional operating restrictions. Any additional costs or operating restrictions associated with GHG legislation or regulations could have material adverse effects on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

In addition, federal, state, tribal and local agencies are considering or have already implemented regulations related to hydraulic fracturing. Hydraulic fracturing involves using water, sand, and certain chemicals pumped at high pressure to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The hydraulic-fracturing process is typically regulated by state oil and natural gas agencies, although the EPA and other federal regulatory agencies have taken steps to impose federal regulatory requirements. Certain states in which we operate or own interests, such as Colorado, Texas and Wyoming have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas

(RCT) and the public of certain information regarding the components used in the hydraulic-fracturing process, and the RCT adopted rules regarding the same in December 2011. We currently voluntarily disclose all chemicals used in our hydraulic fracturing through FracFocus (http://fracfocus.org), the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission, two organizations whose missions both revolve around conservation and environmental protection. Nevertheless, the EPA is considering a citizen petition to adopt federal standards for the disclosure of hydraulic fracturing fluids under the Toxic Substances Control Act.

Federal Regulation of Sales and Transportation of Natural Gas. Our sales of natural gas are affected directly or indirectly by the availability, terms and cost of natural gas transportation. The prices and terms for access to pipeline transportation of natural gas are subject to extensive federal and state regulation. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

Pursuant to authority delegated to it by the Energy Policy Act of 2005, or EPAct 2005, FERC promulgated anti-manipulation regulations establishing violation enforcement mechanisms which make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to use or employ any device, scheme, or artifice to defraud, to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity. Violation of these requirements, similar to violations of other NGA and FERC enforcement authorities, may be subject to investigation and penalties of up to $1 million per day per violation. FERC may also order disgorgement of profit and corrective action. We believe, however, that neither the EPAct 2005 nor the regulations promulgated by FERC as a result of the EPAct 2005 will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Our sales of natural gas and oil are also subject to market manipulation and anti-disruptive requirements under the Commodity Exchange Act, or CEA, as amended by the Dodd-Frank Financial Reform Act, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. CFTC prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

The current statutory and regulatory framework governing interstate natural gas transactions is subject to change in the future, and the nature of such changes is impossible to predict. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the EPA, the FERC, the CFTC and the courts. The natural gas industry historically has been very heavily regulated. In the past, the federal government regulated the prices at which natural gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. There is always some risk, however, that Congress may reenact price controls in the future. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action the FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by the FERC and Congress will continue. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other crude oil and condensate producers.

International Regulations. Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above. These regulations are imposed by the respective governments of the countries in which we operate and may affect our operations and costs within that country. We currently have offshore oil operations in China. Our China business is being held for sale and considered a "discontinued operation." In early February 2014, we closed the sale of our Malaysian business for approximately $898 million.

Financial Information

Financial information regarding the geographic areas in which we operate is incorporated herein by reference to Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 8, “Financial Statements and Supplementary Data.” Risks associated with our international operations are discussed under Item 1A, "Risk Factors," which information is incorporated herein by reference.

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business and in this report.

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

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

Bcf. Billion cubic feet.

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

BLM. The Bureau of Land Management of the United States Department of the Interior.

BOE. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate or 42 gallons for NGLs.

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

BSEE. Bureau of Safety and Environmental Enforcement.

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

Completion. The installation of permanent equipment for the production of oil or natural gas.

Deepwater. Generally considered to be water depths in excess of 1,000 feet.

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

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

Exploitation well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drill are located in the Mid-Continent or the Monument Butte field. Exploitation wells in those areas have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration well. An exploration well is a well drilled to find a new field or new reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

FERC. The Federal Energy Regulatory Commission.

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

FPSO. A floating production, storage and off-loading vessel commonly used overseas to produce oil from locations where pipeline infrastructure is not available.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

Infill drilling or infill well. A well drilled between known producing wells to improve oil and gas reserve recovery efficiency.

Liquids. Crude oil and NGLs.

Liquids-rich. Formations that contain crude oil or NGLs instead of, or as well as, natural gas.

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

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One thousand cubic feet of natural gas produced per day.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

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

MMBOE. One million barrels of oil equivalent, which includes crude oil and condensate, NGLs and natural gas. 1 MMBOE equals 6 Bcf.

MMBtu. One million Btus.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

MMMBtu. One billion Btus.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells.

NGL. Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasolines.

NYMEX. The New York Mercantile Exchange.

NYMEX Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

ONRR. Office of Natural Resources Revenue.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. The SEC provides a complete definition of probable reserves in Rule 4-10(a)(18) of Regulation S-X.

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

Proved developed reserves. In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

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

Proved undeveloped reserves. In general, proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

Reserve life index. This index is calculated by dividing total proved reserves on an equivalent basis at year-end by annual production to estimate the number of years of remaining production.

Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

SEC pricing. The unweighted average first-day-of-the-month commodity price for crude oil (WTI) or natural gas (NYMEX) for the prior 12 months, adjusted for market differentials. The SEC provides a complete definition of prices in “Modernization of Oil and Gas Reporting” (Final Rule).

Unconventional resource plays. Plays targeting tight sand, coal bed or shale reservoirs. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require horizontal drilling and stimulation treatments or other special recovery processes in order to produce economically.

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

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

WTI. West Texas Intermediate, a grade of crude oil.

Item 1A. Risk Factors

There are many factors that may affect Newfield's business and results of operations. Described below are certain risks that we believe are applicable to our business and the oil and gas industry in which we operate. You should carefully consider, in addition to the other information contained in this report, the risks described below.

Oil, gas and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability and future growth, as well as liquidity and ability to access additional sources of capital, depend substantially on prevailing prices for oil, gas and NGLs. Lower prices may reduce the amount of oil, gas and NGLs that we can economically produce. Oil, gas and NGL prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital.

The markets for oil, gas and NGLs have historically been, and will likely remain, volatile. The market prices for crude oil, natural gas and NGLs depend on factors beyond our control. Among the factors that can cause fluctuations are:

- the domestic and foreign supply of oil, natural gas and NGLs;
- the price and availability of, and demand for, alternative fuels;
- weather conditions and climate change;
- changes in supply and demand;
- world-wide economic conditions;
- world-wide conservation measures;
- technological advances affecting energy consumption;
- the price of foreign imports;
- the availability, proximity and capacity of transportation and processing facilities;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- political conditions in oil and gas producing regions;
- the actions taken by foreign oil and gas producing nations;
- the actions taken by the Organization of Petroleum Exporting Countries; and
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental regulation.

Significant declines in crude oil, natural gas and NGL prices for an extended period may have the following effects on our business:

- limiting our access to sources of capital, such as equity and long-term debt;
- causing us to delay or postpone capital projects;
- reducing reserves and the amount of products we can economically produce;

•reducing revenues, income and cash flows; or
•reducing the carrying value of our assets.

We have substantial capital requirements to fund our business plans that we expect to be greater than cash flows from operations. Limited liquidity would likely negatively impact our ability to execute our business plan. We anticipate that our 2014 capital investment levels will exceed our estimate of cash flows from operations. We expect to use available capacity under our credit arrangements and sell non-strategic assets to fund the shortfall. Our ability to generate operating cash flows is subject to many risks and variables, such as the level of production from existing wells, prices of natural gas and oil, our success in developing and producing new reserves and the other risk factors discussed herein. Actual levels of capital expenditures may vary significantly due to many factors including drilling results, commodity prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We may have to reduce capital expenditures, and our ability to execute our business plans could be adversely affected, if:

•we are unable to access the capital markets at a time when we would like, or need, to raise capital;
•one or more of the lenders under our existing credit arrangements fails to honor its contractual obligation to lend to us;
•the amount that we are allowed to borrow under our existing credit facility is reduced; or
•our customers or working interest owners default on their obligations to us.

Actual quantities of oil, gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates. Estimating accumulations of oil, gas and NGLs is complex. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires a number of economic assumptions, such as oil, gas and NGL prices, drilling and operating expenses, capital expenditures, the effect of government regulation, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

•the quality and quantity of available data;
•the interpretation of that data;
•the accuracy of various mandated economic assumptions; and
•the judgment of the persons preparing the estimate.

The proved reserve information set forth in this report is based on our prepared estimates. Estimates prepared by others might differ materially from our estimates.

Actual quantities of oil, gas and NGL reserves, future production, oil, gas and NGL prices, revenues, taxes, development expenditures and operating expenses will most likely vary from our estimates. In addition, the methodologies and evaluation techniques that we use, which include the use of multiple technologies, data sources and interpretation methods, may be different than those used by our competitors. Further, reserve estimates are subject to the evaluator’s criteria and judgment and show important variability, particularly in the early stages of development. Any significant variance could materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of reserves to reflect production history, results of exploration and development activities and prevailing oil, gas and NGL prices. Our reserves also may be susceptible to drainage by operators on adjacent properties.

You should not assume that the present value of future net cash flows is the current market value of our proved reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on SEC 12-month pricing, adjusted for market differentials and costs in effect at year-end discounted at 10%. Actual future prices and costs may be materially higher or lower than the prices and costs we used. In addition, actual production rates for future periods may vary significantly from the rates assumed in the calculation.

To maintain and grow our production and cash flows, we must continue to develop existing reserves and locate or acquire new reserves. Through our drilling programs and the acquisition of properties, we strive to maintain and grow our production and cash flows. However, as we produce from our properties, our reserves decline. Future natural gas and oil production is, therefore, highly dependent on our success in efficiently finding, developing or acquiring additional reserves that are economically recoverable. We may be unable to find, develop or acquire additional reserves or production at an acceptable cost, if at all. In addition, these activities require substantial capital expenditures.

Lower oil and gas prices and other factors have resulted in ceiling test writedowns in the past and may in the future result in additional ceiling test writedowns or other impairments. We capitalize the costs to acquire, find and develop our oil and gas properties under the full cost accounting method. The net capitalized costs of our oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties. If net capitalized costs of our oil and gas properties exceed this limit, we must charge the amount of the excess to earnings. This is called a "ceiling test writedown." We evaluate the ceiling test quarterly and recorded a ceiling test writedown of approximately $1.5 billion ($948 million after-tax) at December 31, 2012. We did not have a ceiling test writedown in 2013. Although a ceiling test writedown does not impact cash flows from operations, it does reduce our stockholders' equity and could negatively impact certain debt covenants. Once recorded, a ceiling test writedown is not reversible at a later date even if oil and gas prices increase.

We may experience further ceiling test writedowns or other impairments in the future. The risk that we will be required to further writedown the carrying value of our oil and gas properties increases when oil and gas prices are low or volatile. In addition, writedowns may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. Any future ceiling test cushion would be subject to fluctuation as a result of acquisition or divestiture activity.

Drilling is a high-risk activity. In addition to the numerous operating risks described in more detail below, the drilling of wells involves the risk that no commercially productive oil or gas reservoirs will be encountered. In addition, we are often uncertain of the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- adverse weather conditions and changes in weather patterns;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- embedded oilfield drilling and service tools;
- equipment failures or accidents;
- lack of necessary services or qualified personnel;
- availability and timely issuance of required governmental permits and licenses;
- availability, costs and terms of contractual arrangements, such as leases, pipelines and related facilities to gather, process and compress, transport and market natural gas, crude oil and related commodities; and
- compliance with, or changes in, environmental, tax and other laws and regulations.

The oil and gas business involves many operating risks that can cause substantial losses. Our oil and gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and gas, including the risk of:

- fires and explosions;
- blow-outs;
- uncontrollable or unknown flows of oil, gas or well fluids;
- formations with abnormal pressures;
- pipe or cement failures and casing collapses;
- pipeline ruptures;
- adverse weather conditions or natural disasters;
- discharges of toxic gases;
- buildup of naturally occurring radioactive materials;
- vandalism; and

•environmental damages caused by previous owners of property we purchase and lease.
If any of these events occur, we could incur substantial losses as a result of:
•injury or loss of life;
•severe damage or destruction of property and equipment, and oil and gas reservoirs;
•pollution and other environmental damage;
•investigatory and clean-up responsibilities;
•regulatory investigation and penalties or lawsuits;
•limitation on or suspension of our operations; and
•repairs to resume operations.

Further, offshore and deepwater operations are subject to a variety of additional operating risks, such as capsizing, collisions and damage or loss from typhoon or other adverse weather conditions. These conditions could cause substantial damage to facilities and interrupt production. Our international operations are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities that we do not own. Necessary infrastructures have been in the past, and may be in the future, temporarily unavailable due to adverse weather conditions or other reasons, or they may not be available to us in the future on acceptable terms or at all.

Failure or loss of equipment, as the result of equipment malfunctions, cyber-attacks or natural disasters, could result in property damages, personal injury, environmental pollution and other damages for which we could be liable. Catastrophic occurrences giving rise to litigation, such as a well blowout, explosion or fire at a location where our equipment and services are used, may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture could result in extensive environmental pollution and substantial remediation expenses. If our production is interrupted significantly, our efforts at containment are ineffective or litigation arises as the result of a catastrophic occurrence, our cash flows, and in turn, our results of operations, could be materially and adversely affected.

In connection with our operations, we generally require our contractors, which include the contractor, its parent, subsidiaries and affiliate companies, its subcontractors, their agents, employees, directors and officers, to agree to indemnify us for injuries and deaths of their employees, contractors and subcontractors and any property damage suffered by the contractors. There may be times, however, that we are required to indemnify our contractors for injuries and other losses resulting from the events described above, which indemnification claims could result in substantial losses to us.

While we maintain insurance against some potential losses or liabilities arising from our operations, our insurance does not protect us against all operational risks. The occurrence of any of the foregoing events and any costs or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage or not indemnified, could reduce revenue and the funds available to us for our exploration, exploitation, development and production activities and could, in turn, have a material adverse effect on our business, financial condition and results of operations. See also "— We may not be insured against all of the operating risks to which our business is exposed."

We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business. Existing and potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development and the production and sale of oil, gas and NGLs are subject to extensive federal, state, provincial, tribal, local and international regulation. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include the following, in addition to the other matters discussed under the caption "Regulation" in Items 1 and 2 of this report:

•the amounts and types of substances and materials that may be released into the environment;
•response to unexpected releases into the environment;

- reports and permits concerning exploration, drilling, production and other operations;
- the placement and spacing of wells;

•unitization and pooling of properties;
•calculating royalties on oil and gas produced under federal and state leases; and
•taxation.

Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs, natural resource risk mitigation, damages and other environmental damages. We also could be required to install expensive pollution control measures, engage in environmental risk management and hedging activities or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. In addition, failure to comply with applicable laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition, results of operations or cash flows.

Further, changes to existing environmental regulations or the adoption of new regulations may unfavorably impact us, the oil and gas industry generally, our suppliers or our customers. For example, governments around the world have become increasingly focused on regulating greenhouse gas (GHG) emissions and addressing the impacts of climate change in some manner. In the absence of dedicated federal legislation on climate change mitigation or adaptation, the EPA has promulgated several rulemakings to regulate, measure or monitor GHG emissions under the existing provisions of the Clean Air Act, or CAA. The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, as well as from certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities on an annual basis. The new regulations could impact certain facilities in which we have interests (legal, equitable, operated or non-operated) by increasing regulatory risks and reporting requirements.

In December 2009, the EPA issued an “endangerment finding” under the CAA concluding that the current and projected concentrations of GHGs in the atmosphere from motor vehicles threaten the public health and welfare of current and future generations. The finding, once made, required the EPA to begin regulating GHG emissions from new cars and light trucks under the CAA. Indirectly, the EPA argued that it also triggered an EPA obligation to regulate GHG emissions under existing relevant air permitting programs for large stationary sources. On January 2, 2011, the EPA initiated Prevention of Significant Deterioration (PSD) permitting requirements for carbon dioxide and other GHGs from large and modified stationary sources. Permits limiting GHGs have been issued for a variety of new or modified facilities under the Clean Air Act PSD program. GHG emissions also trigger Title V operating permit requirements for new and existing sources that exceed certain established emission thresholds. The PSD permitting requirement is triggered when a new or modified facility emits specified levels of GHGs (e.g., 75,000-100,000 tons per year). Emission levels in excess of these thresholds can then trigger preconstruction permit requirements and application of best available control technology (BACT) as determined on a source-by-source basis. In most cases, based on cost, the BACT compliance option selected for GHGs is increased energy efficiency.

If the U.S. Congress adopts market-based tax, energy or other mechanisms to regulate the carbon intensity of natural resources, or promote or require the reduction of GHG emissions from certain industrial sectors, such legislation, depending on design and scope, could increase the cost of oil and gas production and market demand. Some states, like California, have implemented state-wide GHG mitigation programs to reduce GHG emissions through a mixture of regulatory programs, including a low carbon fuel standard and cap-and-trade market applicable to, among others, electric utilities and transportation fuels.

Further, the U.S. Congress has previously proposed legislation that would directly impact our industry. In response to the 2010 Macondo incident in the Gulf of Mexico, the U.S. Congress was considering a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws or regulations governing our operations in the United States, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990.

These and other potential regulations, if introduced and passed in Congress, could increase our costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows. See also "— The potential adoption of federal, state, tribal and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells."

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or regulations could have a material adverse effect on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

The potential adoption of federal, state, tribal and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic-fracturing techniques on almost all of our U.S. onshore oil and natural gas properties. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, the BLM and other federal regulatory agencies have taken steps to review or impose federal regulatory requirements. Certain states in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the RCT and the public of certain information regarding the components used in the hydraulic-fracturing process, and the RCT adopted rules regarding the same in December 2011. On September 11, 2012, the RCT approved new regulations relating to the commercial recycling of produced water and/or hydraulic-fracturing flowback fluid, and on December 17, 2012, proposed revised amendments to rules of casing, cementing, well control and completion of oil and gas wells.

In the past three years, news reports indicate that around two dozen states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local or municipal legal restrictions are adopted in areas where we are currently conducting operations, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Notwithstanding state regulatory requirements relating to hydraulic fracturing, there are steps by federal governmental agencies that are either underway or are being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and recently released draft permitting guidance for hydraulic fracturing activities using diesel. Further, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and gas exploration and production. In addition, in May 2013, the BLM issued a proposed rule that would require the public disclosure of chemicals used in hydraulic fracturing operations, set requirements for well-bore integrity and establish flowback water standards for all hydraulic fracturing operations on federal public lands and American Indian Tribal lands. The proposed rule also required that an operator certify, in writing, that (a) the stimulation design complies with all federal, state, tribal and local regulations; (b) the stimulation was completed in accordance with the design approved by BLM and all applicable regulations; and (c) the well-bore integrity was maintained during the fracturing process and flowback water was properly stored, treated and disposed. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with draft results to be issued in 2014 for public comment and peer review. In addition, the U.S. Department of Energy has conducted an investigation into practices to better protect the environment from drilling using hydraulic fracturing completion methods. In a November 18, 2011 report, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued 20 recommendations to federal agencies, states and private entities that are intended to reduce the environmental impact and assure the safety of shale gas production.

Given the heightened awareness regarding the use of hydraulic fracturing, it is possible that regulatory agencies or private parties may suggest that hydraulic fracturing has caused groundwater contamination, whether or not such allegations are accurate. For example, on December 8, 2011, the EPA released a preliminary report indicating that hydraulic fracturing is responsible for groundwater contamination in Pavillion, Wyoming, although the EPA's draft report has been hotly criticized as ignoring certain facts and utilizing incorrect data. In addition, the EPA has alleged in an enforcement action against an operator in Texas that the operator contaminated local groundwater wells, although the RTC found after an evidentiary hearing that the operator was not responsible for the contamination. However, in 2013 the EPA deferred the Pavillion matter to state oversight and withdrew the emergency action order in Texas. Nevertheless, energy extraction, with a focus on onshore natural gas production, remains an EPA enforcement initiative. Thus, regulatory agencies or private parties alleging groundwater contamination linked to hydraulic fracturing could trigger defense costs in administrative or civil litigation to rebut the allegations.

Additionally, certain members of the Congress have called upon (a) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, (b) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and (c) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Further, 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 finalized rules under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA regulations include NSPS standards for completions of hydraulically-fractured gas wells. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions. After January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAPS include specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. We are currently evaluating the effect these regulations could have on our business. Compliance with such regulations could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Based on the foregoing, increased regulation and attention given to the hydraulic-fracturing process from federal agencies, various states and local governments could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic-fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

We could be adversely affected by the credit risk of financial institutions. We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry. In the event of default of a counterparty, we would be exposed to credit risks. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facility.

Our use of oil and natural gas price hedging contracts may limit future revenues from price increases and involves the risk that our counterparties may be unable to satisfy their obligations to us. As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 24-36 months to reduce our exposure to fluctuations in oil and natural gas prices. As of December 31, 2013, we had no outstanding derivative contracts related to our NGL production. In the case of acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the relevant underlying commodity reference prices and those of our physical pricing points. While the use of hedging arrangements may limit the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements and expose us to the risk of financial loss in certain circumstances. Those circumstances include instances where our production is less than the hedged volume or there is a widening of price basis differentials between delivery points for our production and the delivery points assumed in the hedge transactions.

The use of hedging transactions also involves the risk that counterparties, which generally are financial institutions, will be unable to perform their financial and other obligations under such transactions. If any of our counterparties were to default on its obligations to us under the hedging contracts, enter receivership or seek bankruptcy or similar protection, that could result in an economic loss to us and could have a material adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened, and it is possible that fewer counterparties will participate in future hedging transactions, which could result in greater concentration of our exposure to any one counterparty or a larger percentage of our future production being subject to commodity price changes.

Federal legislation regarding swaps could adversely affect the costs of, or our ability to enter into, those transactions. On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Reform Act) was enacted to establish federal oversight and regulation of the over-the-counter derivatives market and over entities, such as Newfield, that participate in that market. The Dodd-Frank Reform Act includes provisions that require certain over-the-counter derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. The Commodity Futures Trading Commission (CFTC) has begun to formally determine the types of swaps that will be subject to the mandatory clearing and exchange trading requirements. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end-users, can choose to exempt their hedging transactions from these clearing and exchange trading requirements. If our swap activities are not exempt from mandatory clearing or exchange trading, or from margin requirements for uncleared swaps, we could be subject to higher costs, including from higher margin requirements, for those activities.

There are substantial costs associated with the Dodd-Frank Reform Act that create disincentives for end-users like Newfield to hedge their commercial risks, including market price fluctuations associated with anticipated production of oil and gas. The Dodd-Frank Reform Act and related rules and regulations promulgated by CFTC could potentially increase the cost of Newfield’s swap contracts (including through requirements to post margin or collateral for cleared and uncleared swaps), which could adversely affect our available liquidity, materially alter the terms of our swap contracts, reduce the availability of swaps to hedge or mitigate risks we encounter, reduce our ability to monetize or restructure existing swap contracts, and increase our regulatory compliance costs related to our swap activities. In addition, if we reduce our use of swaps, our results of operations and cash flows may be adversely affected, including by becoming more volatile and less predictable, which also could adversely affect our ability to plan for and fund capital expenditures. It is also possible that the Dodd-Frank Reform Act and related rules and regulations could affect prices for commodities that we purchase, use or sell, which, in turn, could adversely affect our liquidity or financial condition.

In December 2013, the CFTC re-proposed rules under the Dodd-Frank Reform Act to expand aggregate position limits to include swaps that are economically equivalent to certain types of commodity futures, including specified energy commodity futures and related transactions, which could apply to swap transactions in which we engage beyond certain thresholds. Certain bona fide hedging transactions or positions would be exempt from those limits, and the rules could require additional oversight monitoring and reporting. If the position limit regulations are ultimately adopted substantially in the form proposed, they could result in additional compliance costs and alter our ability to effectively manage our commercial risks.

Some of our undeveloped leasehold acreage is subject to leases that will expire unless production is established on units containing the acreage. Leases on oil and gas properties normally have a term of three to five years and will expires unless, prior to expiration of the lease term, production in paying quantities is established. If the leases expire and we are unable to renew them, we will lose the right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation. In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, among other proposals:

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

These proposals were also included in President Obama’s Proposed Fiscal Year 2014 Budget. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of such legislation or any other similar changes in U.S. Federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

There is limited transportation and refining capacity for our black and yellow wax crude oil, which may limit our ability to sell our current production or to increase our production in the Uinta Basin. Most of the crude oil we produce in the Uinta Basin is known as “black wax” or “yellow wax” because it has higher paraffin content than crude oil found in most other major North American basins. Due to its wax content, the oil is heated in the field and transported in insulated trucks during shipping. At this time, our transportation options are limited. Substantially all of our production is transported by truck to refiners in the Salt Lake City area. We are exploring the feasibility of transporting future oil volumes by rail or pipeline. We currently have agreements in place with area refiners that secure base load sales of substantially all of our expected production in the Uinta Basin through the end of 2016. In addition, we have executed long-term supply agreements (7 and 10 years) with Tesoro (began in 2013) and HollyFrontier (expected to begin in 2015), who are expanding their local refineries. The inability of Tesoro or HollyFrontier to complete their expansions or an extended loss of any of our largest purchasers or an inability to secure new markets outside of the Salt Lake City area could have a material adverse effect on us because there are limited purchasers of our black and yellow wax crude oil.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control. The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. We deliver oil and gas through gathering systems and pipelines that we do not own. The lack of available capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through some firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, or may not be available to us in the future at a price that is acceptable to us. Federal and state regulation of natural gas and oil production, processing and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints and general economic conditions could adversely affect our ability to produce, gather and transport natural gas. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash flows.

We have risks associated with our non-U.S. operations. Ownership of property interests and production operations in areas outside the United States are subject to the various risks inherent in international operations. These risks may include:

- currency restrictions and exchange rate fluctuations;
- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrection or other changes in government;
- increases in taxes and governmental royalties;
- forced renegotiation of, unilateral changes to, or termination of contracts with, governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations of non-U.S. based companies;
- our limited ability to influence or control the operation or future development of non-operated properties;
- the operator’s expertise or other labor problems;
- cultural differences;

- difficulties enforcing our rights against a governmental entity because of the doctrine of sovereign immunity and foreign sovereignty over international operations; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

Our international operations may also be adversely affected by the laws and policies of the United States affecting foreign trade, taxation and investment. In addition, if a dispute arises with respect to our international operations, we may be subject to the exclusive jurisdiction of non-U.S. courts or may not be successful in subjecting non-U.S. persons to the jurisdiction of the courts of the United States.

Exploration in international deepwater involves significant financial risks, and we may be unable to obtain the drilling rigs or support services necessary for our deepwater drilling and development programs in a timely manner or at acceptable rates. Much of our international deepwater play lacks the physical and oilfield service infrastructure necessary for production. As a result, development of a deepwater discovery may be a lengthy process and requires substantial capital investment, and it is difficult to estimate the timing of our production. Because of the size of significant projects in which we invest, we may not serve as the operator. As a result, we may have limited ability to exercise influence over operations related to these projects or their associated costs. Our dependence on the operator and other working interest owners for these deepwater projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital or lead to unexpected future losses.

Competition for, or the loss of, our senior management or experienced technical personnel may negatively impact our operations or financial results. To a large extent, we depend on the services of our senior management and technical personnel and the loss of any key personnel could have a material adverse effect on our business, financial condition and operating results. Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain a seasoned management team and experienced explorationists, engineers, geologists and other professionals. Competition for these professionals remains strong. We are likely to continue to experience increased costs to attract and retain these professionals.

Competition in the oil and gas industry is intense. We operate in a highly competitive environment for acquiring properties and marketing oil, gas and NGLs. Our competitors include national oil and gas companies, major oil and gas companies, independent oil and gas companies, individual producers, financial buyers as well as participants in other industries supplying energy and fuel to consumers. Many of our competitors have greater and more diverse resources than we do. In addition, high commodity prices and stiff competition for acquisitions have in the past, and may in the future, significantly increase the cost of available properties. We compete for the personnel and equipment required to explore, develop and operate properties. Our competitors also may have established long-term strategic positions and relationships in areas in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for certain drilling rights if our competitors are seeking the same.

Shortages of oilfield equipment, services, supplies and qualified field personnel could adversely affect financial condition and results of operations. Historically, there have been shortages of drilling rigs and other oilfield equipment as demand for that equipment has increased along with the number of wells being drilled. The demand for qualified and experienced field personnel to drill wells and conduct field operations can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. These factors have caused significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment, services and raw materials. Shortages of field personnel, drilling rigs, other equipment or supplies, or price increases, could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition, results of operations or cash flows, or restrict operations.

We may not be insured against all of the operating risks to which our business is exposed. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, such as well blowouts, explosions, oil spills, releases of gas or well fluids, fires, pollution and adverse weather conditions, which could result in substantial losses to us. See also "— The oil and gas business involves many operating risks that can cause substantial losses." We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our insurance coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our onshore and offshore operations that include coverage for general liability, excess liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers' liability and other coverages. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution and other environmental issues, with broader coverage for sudden and accidental occurrences. For example, we maintain operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operators extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. Volatility and disruption in the financial and credit markets may adversely affect the credit quality of our insurers and impact their ability to pay claims.

Further, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition and results of operations.

We may be subject to risks in connection with acquisitions. As part of our business strategy, we have made and may continue to make acquisitions of properties. However, suitable acquisition properties may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. These risks include that the acquired properties may not produce revenues, reserves, earnings or cash flows at anticipated levels. Also, in pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

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

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

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

We are exposed to counterparty credit risk as a result of our receivables. We are exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. Some of our purchasers and non-operating partners may experience liquidity problems and may not be able to meet their financial obligations to us. Nonperformance by a trade creditor or non-operating partner could result in financial losses.

Hurricanes, typhoons, tornadoes and other natural disasters could have a material adverse effect on our business, financial condition, results of operations and cash flow. Hurricanes, typhoons, tornadoes and other natural disasters can potentially destroy thousands of business structures and homes and, if occurring in the Gulf Coast region of the United States, could disrupt the supply chain for oil and gas products. Disruptions in supply could have a material adverse effect on our business, financial condition, results of operations and cash flow. Damages and higher prices caused by hurricanes, typhoons, tornadoes and other natural disasters could also have an adverse effect on our financial condition due to the impact on the financial condition of our customers.

Our level of indebtedness and the restrictive covenants in the agreements governing our indebtedness and other financial obligations may reduce our operating flexibility. As of December 31, 2013, we had total indebtedness of $3.7 billion, including $0.6 billion in borrowings under our revolving credit facility and money market lines of credit. The indenture governing our outstanding notes and the agreements governing our other indebtedness and financial obligations contain, and any indenture that will govern other debt securities issued by us may contain, various covenants that limit our ability and the ability of specified subsidiaries of ours to, among other things:

- incur additional indebtedness;
- purchase or redeem our outstanding equity interests or subordinated debt;
- make specified investments;
- create liens;
- sell assets;
- engage in specified transactions with affiliates;
- engage in sale-leaseback transactions; and
- effect a merger or consolidation with or into other companies or a sale of all or substantially all of our properties or assets.

These restrictions could limit our ability to:

- obtain future financing;
- make needed capital expenditures;
- plan for, or react to, changes in our business and the industry in which we operate;
- compete with similar companies that have less debt;
- withstand a future downturn in our business or the economy in general; or
- conduct operations or otherwise take advantage of business opportunities that may arise.

Some of the agreements governing our indebtedness and other financial obligations also require the maintenance of specified financial ratios and the satisfaction of other financial conditions. Our ability to meet those financial ratios and conditions, and to comply with other covenants and restrictions in our financing agreements, can be affected by unexpected downturns in business operations beyond our control, such as a volatile energy commodity cost environment or an economic downturn. Accordingly, we may be unable to meet these obligations. This failure could impair our operating capacity and cash flows and could restrict our ability to incur debt or to make cash distributions, even if sufficient funds were available.

Our breach of any of these covenants could result in a default under the terms of the relevant indebtedness, which could cause such indebtedness or other financial obligations to become immediately due and payable. If the lenders accelerate the repayment of borrowings or other amounts owed, we may not have sufficient assets to repay our indebtedness or other financial obligations, including our outstanding notes and any future debt securities. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, or repay such debt with the proceeds from a sale of assets or a public offering of securities. Factors that will affect our ability to successfully complete a public offering, refinance our debt or conduct an asset sale include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet

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our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations.

Our certificate of incorporation, bylaws, some of our arrangements with employees and Delaware law contain provisions that could discourage an acquisition or change of control of our Company. Our certificate of incorporation and bylaws contain provisions that may make it more difficult to affect a change of control of our Company, to acquire us or to replace incumbent management. In addition, our change of control severance plan and agreements and our omnibus stock plans contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of restricted stock, restricted stock units and stock options, upon a change of control. Section 203 of the Delaware General Corporation Law also imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions could discourage or prevent a change of control or reduce the price our stockholders receive in an acquisition of our Company.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

In August 2010, we received a Notice of Violation (NOV) from the Environmental Protection Agency (EPA) alleging that we failed to provide adequate financial assurance for water injection wells falling under EPA jurisdiction that are located at our Greater Monument Butte Unit in Duchesne County, Utah (Monument Butte). The injection wells are part of an enhanced oil recovery project designed to optimize production from Monument Butte. Regulations under the Safe Drinking Water Act (SDWA) require operators of injection wells to file proof of financial assurance annually to cover the costs to plug and abandon the injection wells. The NOV alleges that our 2010 and 2009 filings (for 2009 and 2008) did not meet the financial ratio tests that are acceptable as one form of required financial assurance under SDWA regulations. The NOV did not contain any allegations of environmental spills, releases or pollution. Upon receipt of the NOV, we promptly complied with the EPA’s request to put alternate financial assurance in place. We held preliminary discussions with the EPA regarding potential settlement of this matter; however, the EPA determined that the NOV could not be resolved administratively within the EPA’s settlement authority under the SDWA, and therefore required a referral to the Department of Justice (DOJ). Newfield and the EPA signed a consent decree which was lodged with the Utah federal district court on October 23, 2013. The EPA published the notice of the consent decree in the Federal Register on October 31, 2013, which began a 30-day comment period. No comments were received by the EPA. The court entered the consent decree as a final order on December 12, 2013. Newfield paid the civil penalty on December 13, 2013. The matter is now concluded and in three years, Newfield may request the court to terminate the consent decree subject to certain conditions in the decree.

We have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (a) claims from royalty owners for disputed royalty payments, (b) commercial disputes, (c) personal injury claims and (d) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

The following table sets forth the names of, ages (as of February 24, 2014) of and positions held by our executive officers. Our executive officers serve at the discretion of our Board of Directors.

Name	Age	Position	Total Years of Service with Newfield
Lee K. Boothby	52	President, Chief Executive Officer and Chairman of the Board	14
Lawrence S. Massaro	50	Executive Vice President and Chief Financial Officer	3
Gary D. Packer	51	Executive Vice President and Chief Operating Officer	18
Terry W. Rathert	61	Executive Vice President and Senior Advisor	24
George T. Dunn	56	Senior Vice President — Development	21
William D. Schneider	62	Senior Vice President — Exploration	25
Stephen C. Campbell	45	Vice President — Investor Relations	14
George W. Fairchild, Jr.	46	Chief Accounting Officer and Assistant Corporate Secretary	2
Clay M. Gaspar	41	Vice President — Mid-Continent	2
Daryll T. Howard	51	Vice President — Rocky Mountains	17
John H. Jasek	44	Vice President — Onshore Gulf Coast	14
John D. Marziotti	50	General Counsel and Corporate Secretary	10

Lee K. Boothby was named Chairman of the Board of Directors in May 2010, Chief Executive Officer in May 2009 and President in February 2009. Prior to this, he was Senior Vice President — Acquisitions and Business Development. From 2002-2007, he was Vice President — Mid-Continent. From 1999-2001, Mr. Boothby was Vice President and Managing Director — Newfield Exploration Australia Ltd. and managed operations in the Timor Sea (divested in 2003) from Perth, Australia. Prior to joining Newfield in 1999, Mr. Boothby worked for Cockrell Oil Corporation, British Gas and Tenneco Oil Company. He serves as a board member for America’s Natural Gas Alliance and the American Exploration and Production Council. He is a member of the Louisiana State University Craft & Hawkins Department of Petroleum Engineering Advisory Committee, the Society of Petroleum Engineers, the Independent Petroleum Association of America and also is a member of Rice University Jones Graduate School of Business Council of Overseers. He holds a degree in Petroleum Engineering from Louisiana State University and a Master of Business Administration from Rice University.

Lawrence S. Massaro was promoted to Executive Vice President and Chief Financial Officer in November 2013. Mr. Massaro joined Newfield in March 2011 and served as Vice President — Corporate Development until November 2013. In this position, he led the Company's business development, strategic planning and product marketing efforts. Prior to joining Newfield, Mr. Massaro served as Managing Director at JP Morgan in its oil and gas investment banking group beginning in 2005 and was Vice President, Corporate Strategy and Business Development while at Amerada Hess Corporation from 1995-2005. He also held various senior petroleum engineering positions at both PG&E Resources from 1992-1994 and at British Petroleum from 1985-1991. Mr. Massaro holds a degree in Petroleum Engineering from Texas A&M University and a Master of Business Administration from Southern Methodist University.

Gary D. Packer was promoted to the position of Executive Vice President and Chief Operating Officer in May 2009. Prior thereto, he was promoted from Gulf of Mexico General Manager to Vice President — Rocky Mountains in November 2004. Mr. Packer joined the Company in 1995. Prior to joining Newfield, Mr. Packer worked for Amerada Hess Corporation in both the Rocky Mountains and Gulf of Mexico divisions. Prior to these roles, he worked for Tenneco Oil Company. He serves as a board member for the Independent Petroleum Association of America (IPAA). He holds a degree in Petroleum and Natural Gas Engineering from Penn State University.

Terry W. Rathert is one of Newfield's founding members and began serving as Executive Vice President and Senior Advisor in November 2013, and will function in this role through August 2014, at which time he will retire. Prior thereto, Mr. Rathert served as Executive Vice President and Chief Financial Officer from May 2009 to November 2013 and as Senior Vice President, Chief Financial Officer and Secretary from 2000 to May 2009. Prior to 2000, Mr. Rathert served as Vice President — Planning and Administration and Secretary beginning in 1997. From 1992-1997, he served as Vice President, Chief Financial Officer and Secretary, and from 1989-1992, he coordinated the Company’s planning and marketing activities. Prior to Newfield, Mr. Rathert was Director of Economic Planning and Analysis for Tenneco Oil Exploration and Production Company. Mr. Rathert serves on Texas A&M University’s Petroleum Engineering Department’s Industry Board, the Texas Alliance of

Energy Producers Wildcatters Host Committee and the board of directors of the YMCA of Greater Houston. Mr. Rathert has a degree in Petroleum Engineering from Texas A&M University and completed the Management Program at Rice University.

George T. Dunn was promoted to Senior Vice President — Development in September 2012, previously serving as Vice President — Mid-Continent beginning in October 2007. He managed our onshore Gulf Coast operations from 2001 to October 2007, and was promoted from General Manager to Vice President in November 2004. Before managing our Gulf Coast operations, Mr. Dunn was the general manager of our Western Gulf of Mexico division. Prior to joining Newfield in 1992, Mr. Dunn was employed by Meridian Oil Company and Tenneco Oil Company. He holds a degree in Petroleum Engineering from the Colorado School of Mines.

William D. Schneider was promoted to Senior Vice President — Exploration in September 2012, previously serving as Vice President — Gulf of Mexico and International beginning in February 2011. Prior to that, Mr. Schneider served as Vice President — Onshore Gulf Coast and International from December 2008 until February 2011. He has managed our international operations since May 1997. He served as Manager — Exploration from 1992-1997, Technical Coordinator from 1991-1992 and was a geologist from 1989-1990. Mr. Schneider was one of our founding members. Prior to Newfield, Mr. Schneider was Division Geologist in the Western Gulf Division of Tenneco Oil Exploration and Production Company. Mr. Schneider holds Bachelor of Arts and Master of Arts degrees in Geology from Boston University. He is an active member of the IPAA, where he served as Chairman of the International Committee and member of the board of directors from 1999-2009, and the American Petroleum Geologists.

Stephen C. Campbell was promoted to Vice President — Investor Relations in December 2005, after serving as Newfield's Manager — Investor Relations since 1999. Prior to joining Newfield, Mr. Campbell was the Investor Relations Manager at Anadarko Petroleum Corporation from 1993-1999 and the Assistant Vice President of Marketing & Communications at United Way, Texas Gulf Coast from 1990-1993. He is a member of the National Investor Relations Institute. He holds a Bachelor of Science degree in Journalism from Texas A&M University.

George W. Fairchild, Jr. was promoted to Chief Accounting Officer and Assistant Corporate Secretary in November 2013. Mr. Fairchild joined Newfield in August of 2012 as Controller and Assistant Corporate Secretary, serving as the Company's Principal Accounting Officer until his promotion in November 2013. Prior to joining Newfield, Mr. Fairchild served as Controller for Sheridan Production Company LLC, a privately-held oil and gas company, beginning in 2009 and was Vice President and Controller of Davis Petroleum Corporation, also a privately-held oil and gas company, from 2006-2009. Prior thereto, Mr. Fairchild was with Burlington Resources Inc., a publicly-held oil and gas company, serving as Senior Manager — Accounting Policy & Research from 2001-2006 and Manager — Internal Audit from 2000-2001. Before joining Burlington Resources Inc., he was with PricewaterhouseCoopers LLP from 1993-2000. Mr. Fairchild served in the U.S. Air Force from 1986-1990. He holds a Bachelor of Business Administration in Accounting from the University of Texas at Austin and is a Certified Public Accountant.

Clay M. Gaspar joined Newfield in July 2012 as Vice President — Mid-Continent. Prior to joining Newfield, Mr. Gaspar spent 16 years with Anadarko Petroleum Corporation where he served as General Manager of Investor Relations from 2011-2012, General Manager, Business Advisor from 2009-2011 and General Manager, East Texas from 2007-2009. From 1996-2007, he served in various engineering and management positions at Anadarko. Mr. Gaspar started his career with Mewbourne Oil Company as a production and drilling engineer where he worked from 1991-1996. He is a member of the Society of Petroleum Engineers and holds a Bachelor of Science degree in Petroleum Engineering from Texas A&M University and a Master of Science degree in Petroleum and Geosciences Engineering from the University of Texas at Austin and is a Registered Professional Engineer in the state of Texas. Mr. Gaspar is a board member of the Oklahoma Oil and Gas Association, the Oklahoma Independent Producers Association and the Oklahoma Energy Resource Board.

Daryll T. Howard has served as Vice President — Rocky Mountains since May 2009. Mr. Howard joined Newfield in 1996. Prior to his current position, Mr. Howard served as Eastern Rocky Mountains Asset Manager since June 2008. Prior thereto, Mr. Howard served in Newfield's Malaysia office and was instrumental in the success and growth of Newfield's international operations. Mr. Howard also previously held several positions of increasing breadth and responsibility in our Gulf of Mexico business unit. Prior to joining Newfield, Mr. Howard worked for Anadarko Petroleum and Shell Oil Company in varying engineering capacities. He is an active member of Western Energy Alliance where he serves on the Board of Directors and the Executive Operating Committee. He holds Bachelor of Science and Master of Science degrees in Petroleum Engineering from Louisiana State University.

John H. Jasek was reappointed as Vice President — Onshore Gulf Coast in February 2011. Prior to that, he was reappointed as Vice President — Gulf of Mexico in December 2008. Mr. Jasek served as Vice President — Gulf Coast from October 2007 until December 2008 while also serving as the manager of our onshore Gulf Coast operations. He previously managed our Gulf of Mexico operations from March 2005 until October 2007, and was promoted from General Manager to Vice President in November 2006. Prior to March 2005, he was a Petroleum Engineer in the Western Gulf of Mexico. Prior to joining Newfield, Mr. Jasek worked for Anadarko Petroleum Corporation and Amoco Production Company. He has a degree in Petroleum Engineering from Texas A&M University.

John D. Marziotti was promoted to General Counsel in August 2007, and was named Corporate Secretary in May 2008. Prior to joining Newfield in 2003, Mr. Marziotti was a partner at the law firm of Strasburger & Price, LLP in their Houston office. Mr. Marziotti has been a licensed attorney in Texas for the past 24 years. He received his Juris Doctor degree from Southern Methodist University and a Bachelor of Arts degree from the College of Charleston and is a member of the State Bar of Texas, the Houston Bar Association, the Association of Corporate Counsel, Texas General Counsel Forum and is a Fellow with the National Association of Corporate Directors.

PART II

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

Market for Common Stock

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol "NFX." The following table sets forth, for each of the periods indicated, the high and low reported sales price of our common stock on the NYSE.

	High	Low
2012:		
First Quarter	$42.47	$33.74
Second Quarter	36.66	25.01
Third Quarter	35.65	27.91
Fourth Quarter	34.79	23.56
2013:		
First Quarter	$30.50	$22.14
Second Quarter	25.73	19.57
Third Quarter	28.41	22.71
Fourth Quarter	32.55	22.79
2014:		
First Quarter (through February 24, 2014)	$26.79	$23.57

On February 24, 2014, the last reported sales price of our common stock on the NYSE was $25.32. As of that date, there were approximately 1,620 holders of our common stock.

Dividends

We have not paid any cash dividends on our common stock and do not intend to do so in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of our common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our Board of Directors. The covenants contained in our credit facility and in the indentures governing our 7 % Senior Subordinated Notes due 2018, our 6 % Senior Subordinated Notes due 2020, our 5¾% Senior Notes due 2022 and our 5 % Senior Notes due 2024 could restrict our ability to pay cash dividends. See "Contractual Obligations" under Item 7 of this report and Note 9, "Debt," to our consolidated financial statements in Item 8 of this report.

Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2013.

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased under the Plans or Programs
October 1 — October 31, 2013	8,965	$27.73	—	—
November 1 — November 30, 2013	3,948	30.12	—	—
December 1 — December 31, 2013	3,469	28.23	—	—

Total	16,382	$28.41	—	—

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards and restricted stock units. These repurchases were not part of a publicly announced program to repurchase shares of our common stock.

Stockholder Return Performance Presentation

The performance presentation shown below is being furnished pursuant to applicable rules of the SEC. As required by these rules, the performance graph was prepared based upon the following assumptions:

- $100 was invested in our common stock, the S&P 500 Index, the Philadelphia Oil/Exploration & Production Index (EPX) and our peer group on December 31, 2008 at the closing price on such date;

- investment in our peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of the period; and

- dividends were reinvested on the relevant payment dates.

For 2013, we updated our peer group due to our strategic transition to an onshore North American resource company.

New Peer Group. Our new peer group consists of Bill Barrett Corp., Carrizo Oil & Gas Inc., EP Energy Corp., Halcon Resources Corp., QEP Resources Inc., Rosetta Resources Inc., SandRidge Energy Inc. and SM Energy Company.

Prior Peer Group. Our prior peer group (first used in our 2012 Report on Form 10-K) consisted of Chesapeake Energy Corporation, Range Resources Corporation, EXCO Resources, Inc., Southwestern Energy Company, Cabot Oil & Gas Corporation, Whiting Petroleum Corporation, Pioneer Natural Resources Company, Noble Energy, Inc., Berry Petroleum Company, Ultra Petroleum Corp., Cimarex Energy Company, Denbury Resources, Inc., QEP Resources, Inc., Plains Exploration & Production Company, SandRidge Energy, Inc., Forest Oil Corporation and Comstock Resources, Inc.

Comparison of Five-Year Cumulative Total Return

Total Return Analysis	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013
Newfield Exploration Company	$ 100.00	$ 244.20	$ 365.11	$ 191.04	$ 135.59	$ 124.71
S&P 500 Index - Total Returns	$ 100.00	$ 126.46	$ 145.51	$ 148.59	$ 172.37	$ 228.19
PHLX SIG Oil Exploration & Production Index	$ 100.00	$ 161.62	$ 198.98	$ 180.95	$ 168.41	$ 213.16
New Peer Group	$ 100.00	$ 170.70	$ 232.77	$ 230.12	$ 194.56	$ 224.42
Old Peer Group	$ 100.00	$ 161.88	$ 178.25	$ 165.96	$ 166.03	$ 227.78

Item 6. Selected Financial Data

SELECTED FIVE-YEAR FINANCIAL DATA

The following table shows selected consolidated financial data derived from our consolidated financial statements set forth in Item 8 of this report. The data should be read in conjunction with Items 1 and 2, "Business and Properties," and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this report.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions, except per share data)				
Statement of Operations Data:					
Oil, gas and NGL revenues[1]	$1,789	$1,476	$1,742	$1,427	$972
Income (loss) from continuing operations	108	(902)	401	412	(658)
Net income (loss)	147	(1,184)	539	523	(542)
Earnings (loss) per share:					
Diluted —					
Income (loss) from continuing operations	$0.80	$(6.70)	$2.97	$3.08	$(5.06)
Diluted earnings (loss) per share	0.94	(8.80)	3.99	3.91	(4.18)
Weighted-average number of shares outstanding for diluted earnings (loss) per share	136	135	135	134	130
Balance Sheet Data (at end of period):					
Total assets	$9,321	$7,912	$8,991	$7,494	$6,254
Long-term debt	3,694	3,045	3,006	2,304	2,037

(1) Continuing operations only.

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

Overview

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids in North America. Our principal areas of operation include the Mid-Continent, the Rocky Mountains and the onshore Gulf Coast.

To maintain and grow our production and cash flows, we must continue to develop existing proved reserves and find or acquire new oil and natural gas reserves to replace those reserves being produced. Our revenues, profitability and future growth depend substantially on prevailing prices for oil, natural gas and NGLs and on our ability to find, develop and acquire oil and natural gas reserves that are economically recoverable. Prices for oil, natural gas and NGLs fluctuate widely and affect:

•the amount of cash flows available for capital expenditures;

•our ability to borrow and raise additional capital; and

•the quantity of oil, natural gas and NGLs that we can economically produce.

Discontinued Operations

In February 2013, we announced our decision to sell our international businesses in China and Malaysia. The decision to sell our international businesses followed a comprehensive review of the Company's strategy in which we decided to focus on our liquids-rich domestic resource areas. During the second quarter of 2013, our international businesses met the criteria to be classified as held-for-sale and reported as discontinued operations. As such, the results of operations for our international businesses are reflected as “discontinued operations” and discussed further in Note 3, "Discontinued Operations," to our consolidated financial statements appearing later in this report.

Malaysia. On February 10, 2014, Newfield International Holdings Inc., a wholly-owned subsidiary of the Company, closed the sale of our Malaysian business to SapuraKencana Petroleum Berhad, a Malaysian public company, for $898 million in cash (subject to customary purchase price adjustments). See Note 1, “Organization and Summary of Significant Accounting Policies,” and Note 3, “Discontinued Operations,” to our consolidated financial statements appearing later in this report for additional information regarding the sale of our Malaysian business.

China. In August of 2013, during the installation of the LF-7 topside facilities by a third-party contractor, a hydraulic jacking system malfunctioned and the installation was suspended. The installation of the facility has been delayed and the potential cost and timing for the reinstallation is uncertain at this time. As a result of this incident, the timing of the China divestiture has been delayed.

Results of Continuing Operations

Our continuing operations consist of exploration, development and production activities in the United States. The production and average realized prices tables below include our Gulf of Mexico operations for 2012. In the current year discussion below, we excluded revenue of $116 million and production of 2,369 MBOE related to our Gulf of Mexico assets that were fully divested in the fourth quarter of 2012 in order to provide a more comparable analysis of our continuing operations.

Revenues. Revenues from continuing operations of $1.8 billion for the year ended December 31, 2013 were 32% higher than 2012. The increase was primarily due to higher liquids production and commodity prices. Our liquids production increased 43% year-over-year. As expected, our natural gas production declined as we continue to focus capital investments on higher-margin liquids production. Approximately 58% of the revenue increase was attributable to increases in oil production in our Mid-Continent, onshore Gulf Coast and Rocky Mountains regions of 47%, 59% and 18%, respectively. Higher realized oil prices also increased revenues along with this favorable volume variance. Additionally, revenues increased 21% due to year-over-year NGL production increases in the Mid-Continent, onshore Gulf Coast and Rocky Mountains regions of 180%, 59% and 23%, respectively, partially offset by lower NGL prices. While natural gas production declined 14%, a 29% increase in the realized price during the period more than offset the negative production impact on revenue.

During the year ended December 31, 2012, our revenues from continuing operations decreased $266 million, or 15%, as compared to the year ended December 31, 2011. The decrease is primarily due to a 35% reduction in realized natural gas prices combined with an 18% decrease in natural gas production. Consistent with our continued focus on increasing our liquids production, a 10% increase in our crude oil and condensate production partially offset the natural decline resulting from reduced investment in natural gas wells in 2012. Increased NGL production of 30% was more than offset by a 30% decline in NGL prices during 2012. The following table reflects our production from continuing operations and average realized commodity prices for the following periods:

	2013	2012	2011
Production:(1)			
Crude oil and condensate (MBbls)	14,200	11,988	10,939
Natural gas (Bcf)	116.1	143.5	175.1
NGLs (MBbls)	5,163	2,608	2,004
Total (MBOE)	38,706	38,521	42,122
Average Realized Prices:(2)			
Crude oil and condensate (per Bbl)	$86.21	$83.99	$85.68
Natural gas (per Mcf)	3.39	2.64	4.05
NGLs (per Bbl)	30.74	31.26	44.42
Crude oil equivalent (per BOE)	45.91	38.10	41.20

(1) Represents our net share of volumes sold regardless of when produced. Excludes natural gas produced and consumed in operations of 8.1 Bcfe in 2013, 7.8 Bcfe in 2012 and 6.7 Bcfe in 2011.

(2) Had we included the realized effects of derivative contracts, the average crude oil realized price would have been $85.77, $84.10 and $81.38 per Bbl for 2013, 2012 and 2011, respectively. Our average realized price for natural gas would have been $3.97, $3.57 and $5.43 per Mcf for the years ended December 31, 2013, 2012 and 2011, respectively. We did not have any derivative contracts associated with NGL production for the periods presented.

Production. For the year ended December 31, 2013, production from continuing operations increased 7%. Crude oil and NGL production increased 43% but was partially offset by decreases in natural gas production across our domestic regions. The decrease in natural gas production was due to natural decline as a result of reduced investment in natural gas wells. More than half of the increase in total liquids was attributable to higher margin crude oil in 2013.

Our 2012 domestic oil, natural gas and NGL production, stated on a barrel of oil equivalent basis, decreased 9% compared to 2011 production. The decrease relates primarily to the sale of assets in the Gulf of Mexico and natural declines in our natural gas assets due to lack of investment as our investments have been focused on oil and liquids projects. Our domestic oil and liquids production increased approximately 13% in 2012 when compared to the prior year.

Operating Expenses.

Year ended December 31, 2013 compared to December 31, 2012

The following table presents information about operating expenses for our continuing operations for the following periods:

	Unit-of-Production Year Ended December 31, 2013	2012	Percentage Increase (Decrease)	Total Amount Year Ended December 31, 2013	2012	Percentage Increase (Decrease)
	(Per BOE)			(In millions)		
Lease operating	$10.67	$10.53	1 %	$413	$406	2 %
Production and other taxes	1.73	1.74	(1)%	67	67	— %
	17.25	17.74	(3)%	668	683	(2)%

Depreciation, depletion and amortization								
General and administrative	5.67	5.48	3	%	219	211	4	%
Ceiling test impairment	—	38.63	n/a		—	1,488	n/a	
Other	0.07	0.38	(82	)%	3	15	(83	)%
Total operating expenses	35.38	74.50	(53	)%	1,370	2,870	(52	)%

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For the year ended December 31, 2013, total operating expenses for continuing operations increased 7% but were flat on a per BOE basis after adjusting for the 2012 ceiling test writedown and operating expenses of $102 million attributable to Gulf of Mexico assets that were fully divested in the fourth quarter of 2012. The components of significant period-to-period change for operating expenses excluding Gulf of Mexico related expenses related to 2012 are as follows:

- Lease operating expenses (LOE) include normally recurring expenses necessary to operate and produce our oil and gas wells, non-recurring well workover and repair-related expenses and the costs to process and transport our production to the applicable sales points. On a unit-of-production basis, lease operating expenses were 13% higher than 2012. The increase was primarily due to fees related to additional NGL processing costs in all basins and increased infrastructure operating costs in the Uinta Basin.

- Production and other taxes were flat on an actual cost and per unit basis. However, on a percent of revenue basis, they fell approximately 1%. This rate reduction is primarily attributable to production tax credits received in the Mid-Continent, onshore Gulf Coast and Uinta basins plus an $8 million adjustment of ad valorem taxes in the Uinta Basin previously expensed in 2012 and prior years. Without the ad valorem tax adjustment in the Uinta Basin, production and other taxes on a percent of revenue basis would have decreased by less than a half of a percent.

- General and administrative (G&A) expense increased during 2013 primarily due to employee-related expenses associated with our Voluntary Severance Program and Stock Value Appreciation Program (see Note 13, "Voluntary Severance Program," and Note 11, "Stock-Based Compensation," to our consolidated financial statements in Item 8 of this report) partially offset by the cost savings generated by the centralization of several administrative functions. During 2013, we capitalized $107 million ($2.77 per BOE) of direct internal costs as compared to $95 million ($2.45 per BOE) during 2012.

- In the fourth quarter of 2012, we recorded a ceiling test writedown of $1.5 billion due to a net decrease in the discounted value of our proved reserves. The primary reason for the change in value was negative price-related reserve revisions as a result of a 33% decrease in the natural gas SEC pricing.

- Other expenses in 2012 of $15 million included a writedown of $8 million of subsea wellhead inventory that was not included in the sale of our Gulf of Mexico assets and contract termination costs of $6 million in consideration of other services.

Year ended December 31, 2012 compared to December 31, 2011

The following table presents information about our operating expenses for our continuing operations for the following periods:

	Unit-of-Production Year Ended December 31,		Percentage Increase (Decrease)	Total Amount Year Ended December 31,		Percentage Increase (Decrease)
	2012	2011		2012	2011	
	(Per BOE)			(In millions)		
Lease operating	$10.53	$8.50	24 %	$406	$358	13 %
Production and other taxes	1.74	1.62	7 %	67	68	(2)%
Depreciation, depletion and amortization	17.74	14.75	20 %	683	621	10 %
General and administrative	5.48	4.26	29 %	211	180	17 %
Ceiling test impairment	38.63	—	n/a	1,488	—	n/a
Other	0.38	—	n/a	15	—	n/a

Total operating expenses	74.50	29.13	156 %	2,870	1,227	134 %

Excluding the ceiling test writedown, the increase in our depletion rate due to price-related downward reserve revisions and the impact of selling our offshore Gulf of Mexico assets, our operating expenses increased 21%. The components of the significant period-to-period change are as follows:

- LOE includes normally recurring expenses necessary to operate and produce our oil and gas wells, non-recurring well workover and repair-related expenses and the costs to transport our production to the applicable sales points. Recurring

LOE increased $0.29 per BOE to $5.56 per BOE. The increase was due to higher compression, fuel, electricity, and rental equipment costs coupled with declining natural gas production in our Mid-Continent region. Partially offsetting this increase, was improved recurring LOE per unit in our Rocky Mountain and Onshore Gulf Coast regions. Increases in our non-recurring LOE of $42 million accounted for 87% of the increase in total domestic LOE primarily due to the following:

- increased workover activity was the primary factor resulting in a $14 million increase in non-recurring LOE in our Rocky Mountain region;
- restimulation of several wells in our effort to improve performance was the leading driver of the $13 million non-recurring LOE increase in our Mid-Continent region;
- repairs to plugged flow lines in our deepwater Gulf of Mexico operations, which were subsequently sold in the fourth quarter of 2012, were the primary driver of an additional increase of $12 million in non-recurring LOE; and
- transportation costs related to firm transportation agreements in our Mid-Continent region accounted for $0.47 per BOE of the increase.

- Our average depreciation, depletion and amortization (DD&A) rate increased $2.99 per BOE during 2012 and reflects our continued focus on oil and liquids rich gas developments that are more capital intensive on a per BOE basis as compared to natural gas developments. While our average DD&A rate in 2011 was $14.75, our rate for the fourth quarter of 2011 was $16.61. During 2012, this rate increased as the additional cost of each BOE added was higher. In addition, the full year average rate was negatively impacted by downward reserve revisions (primarily due to natural gas price declines) combined with the net impact of selling our remaining Gulf of Mexico assets. Without these items, our average DD&A rate for the year ended December 31, 2012 would have been $17.34.

- G&A expense per BOE increased during 2012 primarily due to employee-related expenses associated with our domestic work force combined with lower domestic production. During 2012, we capitalized $95 million ($2.45 per BOE) of direct internal costs as compared to $83 million ($1.98 per BOE) during 2011.

- In the fourth quarter of 2012, we recorded a ceiling test writedown of approximately $1.5 billion ($38.63 per BOE) due to a net decrease in the discounted value of our proved reserves. The primary reason for the change in value was negative price-related reserve revisions as a result of a 33% decrease in the natural gas SEC pricing.

- Other expenses of $15 million ($0.38 per BOE) included a writedown of $8 million of subsea wellhead inventory that was not included in the sale of our Gulf of Mexico assets and contract termination costs of $6 million in consideration of other services.

Interest Expense. The following table presents information about interest expense for each of the years ended December 31:

	2013	2012	2011
	(In millions)		
Gross interest expense:			
Credit arrangements	$11	$9	$11
Senior notes	101	73	11
Senior subordinated notes	93	122	152
Other	—	1	1
Total gross interest expense	205	205	175
Capitalized interest	(53)	(68)	(82)

Net interest expense	$152	$137	$93

Gross interest expense remained flat in 2013 as compared to 2012 due to the restructuring of our senior notes in 2012. The increase in gross interest expense in 2012 as compared to 2011, primarily resulted from the September 2011 issuance of $750 million aggregate principal amount of 5¾% Senior Notes due 2022, as well as the June 2012 issuance of $1 billion aggregate principal amount of 5 % Senior Notes due 2024, partially offset by the redemption in April 2012 of our $325 million 6 % Senior Subordinated Notes due 2014 and in July 2012 of our $550 million 6 % Senior Subordinated Notes due 2016. See Note 9, “Debt,” to our consolidated financial statements in Item 8 of this report.

Interest expense associated with oil and gas properties excluded from amortization is capitalized into oil and gas properties. Capitalized interest decreased in 2013 as compared to 2012 and in 2012 as compared to 2011, due to a reduction in our average balance of oil and gas properties excluded from amortization.

Commodity Derivative Income (Expense). The fluctuations in commodity derivative income (expense) from period to period are due to the volatility of oil and natural gas prices and changes in our outstanding hedging contracts during these periods.

Taxes. The effective tax rates for the years ended December 31, 2013, 2012 and 2011 were 37%, 36% and 35%, respectively. Our effective tax rate for 2013 and 2012 was different than the federal statutory tax rate of 35%, due to non-deductible expenses and state income taxes. Please see the discussion and tables in Note 10, "Income Taxes," to our consolidated financial statements in Item 8 of this report.

Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices; the timing, amount and location of future production; operating expenses; and capital costs.

Results of Discontinued Operations - Malaysia and China

Revenues. Our international revenues are primarily derived from the sale of crude oil. Substantially all of the crude oil from our offshore operations in Malaysia and China is produced into FPSOs, or onshore storage terminals, and "lifted" and sold periodically as barge quantities are accumulated. Revenues are recorded when oil is lifted and sold, not when it is produced into FPSOs. As a result, timing of liftings may impact period-to-period results. In early February 2014, we closed the sale of our Malaysia business. See Note 1, "Organization and Summary of Significant Accounting Policies" and Note 3, "Discontinued Operations," to our consolidated financial statements appearing later in this report for additional information regarding the sale.

For the year ended December 31, 2013, revenues from discontinued operations were $891 million, a decrease of 18% over 2012. The decrease in revenue was primarily due to fewer liftings of crude oil. Revenues of $1.1 billion for 2012 were 50% higher than 2011, mainly due to a 48% increase in liftings of crude oil primarily in Malaysia. The overall price per BOE remained essentially flat during 2013, 2012 and 2011. The following table reflects our production from discontinued operations and average realized commodity prices for the each of the years ended December 31.

	2013	2012	2011
Production:[1]			
Crude oil and condensate (MBbls)	8,177	9,914	6,715
Natural gas (Bcf)	0.5	1.2	0.1
Total (MBOE)	8,268	10,106	6,728
Average Realized Prices:			
Crude oil and condensate (per Bbl)	$ 108.71	$ 109.67	$ 108.51
Natural gas (per Mcf)	3.64	3.89	3.95
Crude oil equivalent (per BOE)	107.76	108.03	108.34

(1) Represents our net share of volumes sold regardless of when produced.

Liftings. Our 2013 total liftings from discontinued operations decreased 18% as compared to 2012. Approximately 65% of the decrease in liftings was due to natural decline. The remainder of the decrease is due to the timing of liftings and the terms of our production sharing contracts (PSCs) in Malaysia, which reduce entitled production as we reach certain cost recovery milestones. Our 2012 total liftings increased by 48% over 2011 levels, primarily due to an increase of 53% in Malaysia production resulting from continued successful drilling on the East Belamut field, as well as full-year production on the East Piatu and Puteri fields, brought online during the fourth quarter of 2011.

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Operating Expenses.

Year ended December 31, 2013 compared to December 31, 2012

The following table presents information about our operating expenses for our discontinued operations for the following periods:

	Unit-of-Production Year Ended December 31, 2013	2012	Percentage Increase (Decrease)	Total Amount Year Ended December 31, 2013	2012	Percentage Increase (Decrease)
	(Per BOE)			(In millions)		
Lease operating	$15.11	$10.73	41 %	$125	$108	15 %
Production and other taxes	34.39	27.40	26 %	284	277	3 %
Depreciation, depletion and amortization	31.71	26.88	18 %	262	272	(3)%
General and administrative	2.12	0.69	206 %	18	7	150 %
Total operating expenses	83.33	65.70	27 %	689	664	4 %

Our operating expenses for discontinued operations for 2013, stated on a BOE basis, increased 27% over 2012. The components of the period-to-period change are as follows:

- LOE per BOE increased 41% ($4.38 per BOE) due to increased service costs related to offshore support operations in Malaysia and mostly-fixed fees associated with producing into onshore storage terminals in Malaysia combined with fewer liftings.

- Production and other taxes per BOE increased 26% due to the terms of our PSCs in Malaysia, which increase production tax rates subsequent to reaching certain cost recovery milestones.

- DD&A expense decreased 3% due to an 18% decrease in liftings during 2013 as compared to 2012, partially offset by an increase in the average DD&A rate. Our DD&A rate per BOE increased 18% in 2013 compared to 2012 due primarily to upward revisions of asset retirement costs in 2013 for Malaysia and the costs of unsuccessful wells in offshore Malaysia and China being included in costs subject to amortization in the second quarter of 2013 without a related increase in reserves.

- G&A expense increased approximately $11 million ($1.43 per BOE) primarily due to increased employee-related costs and other costs associated with our decision to sell our international businesses.

Year ended December 31, 2012 compared to December 31, 2011

The following table presents information about our operating expenses for our discontinued operations for the following periods:

	Unit-of-Production Year Ended December 31, 2012	2011	Percentage Increase (Decrease)	Total Amount Year Ended December 31, 2012	2011	Percentage Increase (Decrease)
	(Per BOE)			(In millions)		
Lease operating	$10.73	$14.15	(24)%	$108	$95	14 %
Production and other taxes	27.40	38.93	(30)%	277	262	6 %
Depreciation, depletion and amortization	26.88	21.59	25 %	272	145	87 %

General and administrative	0.69	0.79	(13	)%	7	6	31	%
Total operating expenses	65.70	75.46	(13	)%	664	508	31	%

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Our operating expenses for discontinued operations for 2012, stated on a BOE basis, decreased 13% over 2011. The components of the period-to-period change are as follows:

- LOE per BOE decreased by 24% ($3.42 per BOE) primarily due to lower non-recurring workover activity during 2012. Recurring LOE was essentially flat on a per unit basis with a decrease of $0.13 per BOE, or 1%.

- Production and other taxes per BOE decreased by 30% due to an overall change in the mix of production that was lifted and sold from the various PSCs in Malaysia including the fields brought online during the fourth quarter of 2011. The production tax rates per barrel of oil lifted and sold from these newer developments were lower, per the terms of the PSCs, while we recovered our costs associated with these developments.

- DD&A expense increased 87% in 2012 compared to 2011 due to a combination of an increase in the average DD&A rate and a 50% increase in production during 2012. DD&A per BOE increased 25% when compared to the 2011 rate. The average annual 2012 rate when compared to the end of 2011 rate of $24.45 was 10% higher and was primarily due to the costs of two unsuccessful wells in offshore Malaysia, which increased the amount subject to depletion without any associated reserve additions.

Liquidity and Capital Resources

The following is inclusive of both our continuing and discontinued operations, unless otherwise noted.

We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this through successful drilling programs and property acquisitions, which require substantial capital expenditures. Lower prices for oil, natural gas and NGLs may reduce the amount of oil and gas that we can economically produce and can also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital, as further described below.

We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our capital budgets (excluding acquisitions) are created based upon our estimate of internally generated sources of cash, as well as the available borrowing capacity of our revolving credit facility. Our 2014 budget will be financed through our cash flows from operations, proceeds from our recent Malaysian sale and the use of our credit facility. Approximately 89% of our expected 2014 domestic oil and gas production (excluding NGLs) supporting the current 2014 capital budget estimate is hedged. Our 2014 capital budget for our continuing operations, excluding estimated capitalized interest and overhead of $182 million, is expected to be approximately $1.6 billion and focuses on liquids-rich projects with higher returns, which we believe generate and lay the foundation for liquids production growth in 2015 and thereafter. Depending on the timing of the sale of our China business, we intend to invest approximately $100 million in China.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results, oil, natural gas and NGL prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired or non-strategic assets sold. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. We believe we have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

We believe that our liquidity position and ability to generate cash flows from our asset portfolio will be adequate to fund 2014 operations.

Credit Arrangements. We maintain a revolving credit facility of $1.4 billion that matures in June 2018, as well as money market lines of credit of $160 million at December 31, 2013, for a total borrowing capacity of $1.6 billion. At December 31, 2013, we had $585 million of LIBOR based loans outstanding against our revolving credit facility and

$64 million outstanding against our money market lines of credit. At December 31, 2013, we had no scheduled maturities of senior notes or senior subordinated notes until 2018. As of December 31, 2013, we had $58 million of undrawn letters of credit related to our Malaysian business outstanding under our credit facility, which were terminated in February 2014 upon the closing of the sale of our Malaysian business. Also in connection with the sale of our Malaysian business, we paid in full amounts previously outstanding under our revolving credit facility and money market lines of credit. For a more detailed description of the terms of our credit arrangements and senior and senior subordinated notes, please see Note 9, “Debt,” to our consolidated financial statements appearing later in this report.

At February 24, 2014, we had no letters of credit or borrowings outstanding under our credit facility. Our available borrowing capacity under our credit arrangements was approximately $1.6 billion.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements, changes in the fair value of our outstanding commodity derivative instruments as well as the timing of receiving reimbursement of amounts paid by us for the benefit of joint venture partners. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. We anticipate that our 2014 capital investment levels will exceed our estimate of cash flows from operations and as a result, we will use proceeds from our recent Malaysian sale along with our credit arrangements to fund the shortfall.

At December 31, 2013 and 2012, we had negative working capital of $389 million and $93 million, respectively. The changes in our working capital are primarily a result of the timing of the collection of receivables, changes in the fair value of our derivative positions, the timing of crude oil liftings in our international operations, drilling activities, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Cash Flows from Operations. Our primary source of capital and liquidity are cash flows from operations and are primarily affected by our production of oil, natural gas and NGLs, as well as commodity prices, net of the effects of settlements of our derivative contracts and changes in working capital.

We typically receive the cash associated with oil and gas sales within 45-60 days of production. As a result, cash flows from operations and income from operations generally correlate, but cash flows from operations are impacted by changes in working capital and are not affected by DD&A, ceiling test writedowns, other impairments or other non-cash charges or credits.

Our net cash flows from operations were approximately $1.4 billion (includes $334 million of cash flows from discontinued operations) in 2013, $1.1 billion in 2012 and $1.6 billion in 2011. The changes in cash flows from operations in 2013 compared to 2012, were primarily as a result of higher cash flows from operating activities due to increased production and prices, and changes in working capital.

Cash Flows from Investing Activities. Net cash used in investing activities for 2013 was $2.1 billion compared to $1.2 billion for 2012. The increase was due to increased capital expenditures combined with fewer asset sales in 2013 compared to 2012.

Cash Flows from Financing Activities. Net cash provided by financing activities for 2013 was $620 million compared to $24 million for 2012. During 2013 we increased our borrowings under our revolving credit facility and money market lines of credit by $649 million to fund capital expenditures, and paid $20 million to repurchase the preferred shares of our now wholly-owned subsidiary, Newfield China, LDC.

Capital Expenditures. Our capital investments of $2.0 billion for 2013 increased 17% from our capital investments of $1.7 billion during 2012. These amounts exclude recorded asset retirement obligations of $125 million and $9 million, and capitalized interest and overhead of $197 million and $191 million in 2013 and 2012, respectively. Of the total $2.0 billion invested during 2013, we invested $1.3 billion in domestic exploitation and development, $218 million in domestic exploration (exclusive of exploitation and leasehold activity), $90 million in leasing domestic proved and unproved property (leasehold), $20 million in pipeline spending, $72 million in acquisitions, $23 million in plug and abandonment settlements and $344 million outside the United States.

Our capital investments of $1.7 billion for 2012 decreased 26% from our capital investments of $2.3 billion during 2011. These amounts exclude recorded asset retirement obligations of $9 million and $33 million and capitalized interest and overhead of $191 million and $194 million in 2012 and 2011, respectively. Of the total $1.7 billion invested during 2012, we invested $1.3 billion in domestic exploitation and development, $153 million in domestic exploration (exclusive of exploitation and leasehold activity), $67 million in leasing domestic proved and unproved property (leasehold), $23 million in plug and abandonment settlements and $225 million outside the United States.

Commitments under Joint Operating Agreements. Most of our properties are operated through joint ventures under joint operating or similar agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a “working interest” basis. The joint operating agreement provides remedies to the operator if a non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2013.

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
	(In millions)				
Continuing operations					
Debt:					
Revolving credit facility	$585	$—	$—	$585	$—
Money market lines of credit	64	—	—	64	—
5¾% Senior Notes due 2022	750	—	—	—	750
5 % Senior Notes due 2024	1,000	—	—	—	1,000
7 % Senior Subordinated Notes due 2018	600	—	—	600	—
6 % Senior Subordinated Notes due 2020	700	—	—	—	700
Total debt	3,699	—	—	1,249	2,450
Other obligations:					
Interest payments	1,545	203	607	323	412
Net derivative (assets) liabilities	36	62	(26)	—	—
Asset retirement obligations	119	4	27	12	76
Operating leases and other(1)	193	79	64	26	24
Firm transportation	445	78	220	114	33
Total other obligations	2,338	426	892	475	545
Total contractual obligations from continuing operations	$6,037	$426	$892	$1,724	$2,995
Discontinued operations					
Other obligations:					
Asset retirement obligations	$136	$50	$69	$7	$10
Operating leases and other(2)	84	72	12	—	—
Oil and gas activities(3)	245	—	—	—	—
Total contractual obligations from discontinued operations(4)	$465	$122	$81	$7	$10

(1) Includes agreements for office space, drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations are related to contracts for office space and drilling rigs, and are included at the gross contractual value. Due to our various working interests where the drilling rig contracts will be utilized, it is not feasible to estimate a net contractual obligation. Net payments under these contracts are accounted for as capital additions to our oil and gas properties and could be significantly less than the gross obligation disclosed.

(2) Includes agreements for office space, drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations are related to contracts for drilling rigs and are included at the gross contractual value. Due to our various working interests where these service contracts will be utilized, it is not feasible to estimate a net contractual obligation. Net payments under these contracts are accounted for as capital additions to our oil and gas properties and could be significantly less than the gross obligation disclosed.

(3) As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work-related commitments for, among other things, drilling wells, platform construction, obtaining and processing seismic data and fulfilling other related commitments. At December 31, 2013, these work-related commitments totaled $245 million, all of which were attributable to our international business. Actual amounts by maturity are not included because their timing cannot be accurately

predicted.

(4) Of the total $465 million of contractual obligations from discontinued operations, $295 million is related to our Malaysian business. In early February 2014, we closed the sale of our Malaysian business and therefore are no longer subject to these obligations.

We have various oil and gas production volume delivery commitments that are related to our domestic operations. Given the size of our proved natural gas and oil reserves and production capacity in the respective divisions, we currently believe that we have sufficient reserves and production to fulfill these commitments. However, in the event that we are unable to meet our crude oil volume delivery commitments, we would incur deficiency fees ranging from $2.67 to $6.50 per barrel. See Items 1 and 2, "Business and Properties" for a description of our production and proved reserves. As of December 31, 2013, our delivery commitments through 2024 were as follows:

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Natural gas (MMMBtus)	11,250	11,250	—	—	—
Oil (MBbls)(1)	102,644	7,483	30,543	27,740	36,878

(1) Our oil delivery commitments include a particular commitment with a Salt Lake City, Utah refiner. This delivery commitment will begin upon the refiner completing the expansion of their facility, which is expected in late 2015. Our delivery commitment is to deliver approximately 20,000 barrels of oil per day over a 10-year period. This delivery commitment represents approximately 7,300 MBbls of our committed oil volumes for each of the years 2016 through 2024. The timing may change due to timing of the completion of the refinery expansion.

Oil and Gas Hedging

We use derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 24-36 months. As of December 31, 2013, we had no outstanding derivative contracts related to our NGL production or production associated with our discontinued operations. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may use basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. We do not use derivative instruments for trading purposes. For a further discussion of our hedging activities, see "Critical Accounting Policies and Estimates — Commodity Derivative Activities" below and "Oil, Natural Gas and NGL Prices" in Item 7A of this report. Please see the discussion and tables in Note 5, "Derivative Financial Instruments," and Note 8, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open contracts and the estimated fair market value of those contracts as of December 31, 2013.

Between January 1, 2014 and February 24, 2014, we entered into additional derivative contracts as set forth below.

Crude Oil

		NYMEX Contract Price Per Bbl	
Period and Type of Instrument	Volume in MBbls	Swaps (Weighted Average)	Sold Puts (Weighted Average)
2015:			
Fixed-price swaps with sold puts	2,054	$ 90.37	$ 71.31
2016:			
Fixed-price swaps with sold puts (1)	637	90.02	70.00

(1) Our fixed-price swaps with sold puts for 2016 are for January through March 2016.

Between January 1, 2014 and February 24, 2014, we also sold crude oil swaption contracts that would potentially hedge 1,548 MBbls of calendar year 2015 production if exercised on their expiration date of May 30, 2014. These contracts give the counterparties the option to enter into swap contracts with us at a weighted average price of $90.29/Bbl.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments as described above under "— Contractual Obligations."

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our 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 gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Described below are the most significant policies we apply in preparing our financial statements, some of which are subject to alternative treatments under generally accepted accounting principles. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with the Audit Committee of our Board of Directors. See Note 1, "Organization and Summary of Significant Accounting Policies," to our consolidated financial statements in Item 8 of this report for a discussion of additional accounting policies and estimates we make.

For discussion purposes, we have divided our significant policies into four categories. Set forth below is an overview of each of our significant accounting policies by category.

- We account for our oil and gas activities under the full cost method. This method of accounting requires the following significant estimates:
  - quantity of our proved oil and gas reserves;
  - costs withheld from amortization; and
  - future costs to develop and abandon our oil and gas properties.
- Accounting for business combinations requires estimates and assumptions regarding the fair value of the assets and liabilities of the acquired company.
- Accounting for commodity derivative activities requires estimates and assumptions regarding the fair value of derivative positions.
- Stock-based compensation costs require estimates and assumptions regarding the grant date fair value of awards, the determination of which requires significant estimates and subjective judgments.

Oil and Gas Activities. Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available — successful efforts and full cost. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed, while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas properties under the successful efforts method is a two-step test that compares the carrying value of the properties to the undiscounted cash flows to see if an impairment is required. If required, the impairment is the difference between the carrying value of individual oil and gas properties and their estimated fair value using forward looking prices. Impairment under the full cost method requires an evaluation of the carrying value of oil and gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using SEC pricing, costs in effect at year-end and a 10% discount rate.

We use the full cost method of accounting for our oil and gas activities. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas activities.

Proved Oil and Gas Reserves. Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization (DD&A) expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of oil and gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs based on SEC pricing and under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil, gas and NGL prices, operating costs and expected performance from a given reservoir also will result in future revisions to the amount of our estimated proved reserves. All reserve information in this report is based on estimates prepared by our petroleum engineering staff.

Depreciation, Depletion and Amortization. Estimated proved oil, gas and NGL reserves are a significant component of our calculation of DD&A expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test writedown. To change our diluted earnings per share for continuing operations by $0.01 for the year ended December 31, 2013, our domestic DD&A rate would need to change by $0.20 per BOE which would require a change in the estimate of our domestic proved reserves of approximately 1%, or 7 MMBOE.

Full Cost Ceiling Limitation. Under the full cost method, we are subject to quarterly calculations of a “ceiling” or limitation on the amount of costs associated with our oil and gas properties that can be capitalized on our balance sheet. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The ceiling value of oil, gas and NGL reserves is calculated based on SEC pricing and costs in effect as of the last day of the quarter.

At December 31, 2013, the ceiling value of our reserves was calculated based upon SEC pricing of $3.67 per MMBtu for natural gas and $96.82 per barrel for oil. Using these prices, the U.S. cost center ceiling exceeded the net capitalized costs of oil and gas properties by approximately $445 million, net of tax, and as such, no ceiling test writedown was required. Holding all other factors constant, it is possible that we could experience a ceiling test writedown in the U.S. if the applicable average oil and natural gas prices declined approximately 6% from prices used at December 31, 2013.

Given the fluctuation of oil, natural gas and NGL prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If commodity prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that additional writedowns of our oil and gas properties could occur in the future.

Costs Withheld From Amortization. Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred or a charge is made against earnings if the costs were incurred in a country for which a reserve base has not been established. If a reserve base for a country in which we are conducting operations has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results, relinquishing drilling rights or other information.

In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with qualifying major development projects may be temporarily excluded from amortization. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and estimated future development costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2013, we had a total of approximately $1.3 billion of costs excluded from the amortization base of our respective full cost pools, the majority of which related to our domestic full cost pool. Inclusion of some or all of our domestic unevaluated property costs in our domestic full cost pool, without adding any associated reserves, would have resulted in a ceiling test writedown.

Future Development and Abandonment Costs. Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and abandonment costs on an annual basis, or more frequently if an event occurs or circumstances change that would affect our assumptions and estimates.

The accounting guidance for future abandonment costs requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Holding all other factors constant, if our estimate of future development and abandonment costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense. To change our diluted earnings per share for continuing operations by $0.01 for the year ended December 31, 2013, our domestic DD&A rate would need to change by $0.20 per BOE which would require a change in estimate of our domestic future development and abandonment costs of approximately 3%, or $118 million.

Allocation of Purchase Price in Business Combinations. As part of our growth strategy, we monitor and screen for potential acquisitions of oil and gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. To the extent the consideration paid exceeds the fair value of the net assets acquired, we are required to record the excess as goodwill. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value allocated to recoverable oil and natural gas reserves and unproved properties is subject to the cost center ceiling as described under "— Full Cost Ceiling Limitation" above. The accounting standard for business combinations establishes how a purchaser recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The standard also sets forth guidance related to the recognition, measurement and disclosure related to goodwill acquired in a business combination or gains associated with a bargain purchase transaction.

Commodity Derivative Activities. Under accounting rules, we may elect to designate certain derivative contracts that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future oil and gas production. We do not designate future price-risk management activities as accounting hedges. Because derivative contracts not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience non-cash volatility in our reported earnings during periods of commodity price volatility. As of December 31, 2013, we had net derivative liabilities of $36 million, of which 33%, based on total hedged volumes, was measured based upon our valuation model (i.e. Black-Scholes) and, as such, is classified as a Level 3 fair value measurement.

In determining the amounts to be recorded for our open hedge contracts, we are required to estimate the fair value of the derivative. Our valuation models for derivative contracts are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying commodities, as well as other relevant economic measures. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the hedge agreements, and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility, as well as changes in future price forecasts, regional price differences and interest rates. As a result, the value of these contracts at their respective settlement dates could be significantly different than the fair value as of December 31, 2013. We periodically validate our valuations using independent third-party quotations.

The determination of the fair value of derivative instruments incorporates various factors which include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests). We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties.

Stock-Based Compensation. We apply a fair value-based method of accounting for stock-based compensation which requires recognition in the financial statements of the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. For equity-based compensation awards, compensation expense is based on the fair value on the grant or modification date and is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option-pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted stock and restricted stock units. We also have cash-settled restricted stock units that are accounted for under the liability method which requires us to recognize the fair value of each award based on the underlying share price at the end of each period, as well as a Stockholder Value Appreciation Program which pays certain employees a cash payment based on increases in our stock price. See Note 11, "Stock-Based Compensation," to our consolidated financial statements in Item 8 of this report for a full discussion of our stock-based compensation.

New Accounting Requirements

In February 2013, the FASB issued guidance regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The guidance is effective for interim and annual periods beginning after December 15, 2012. We adopted the guidance in the quarter ended March 31, 2013. Adoption of the new reporting guidance did not have a material impact on our financial position or results of operations.

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance requires disclosure of both gross and net information about instruments and transactions eligible for offset arrangement. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. We adopted the guidance in the quarter ended March 31, 2013. Adoption of the additional disclosures regarding offsetting assets and liabilities did not have a material impact on our financial position or results of operations.

Regulation

Exploration and development and the production and sale of oil, gas and NGLs are subject to extensive federal, state, provincial, tribal, local and international regulations. An overview of these regulations is set forth in Items 1 and 2, "Business and Properties — Regulation." We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Please see the discussion under the caption "We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business," in Item 1A of this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk from changes in oil, natural gas and NGL prices, interest rates and foreign currency exchange rates as discussed below.

Oil, Natural Gas and NGL Prices

Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements. In addition, the use of hedging transactions may involve basis risk. All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions also involves the risk that the counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2013, nine of our 15 counterparties accounted for approximately 85% of our estimated future hedged production, with no single counterparty accounting for more than 15% of that production. For a further discussion of our hedging activities, see the information under the caption “Oil and Gas Hedging” and “Critical Accounting Policies and Estimates” in Item 7 of this report and the discussion and tables in Note 5, “Derivative Financial Instruments,” to our consolidated financial statements in Item 8 of this report.

Interest Rates

At December 31, 2013, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Revolving credit facility and money market lines of credit	$—	$649
7 % Senior Subordinated Notes due 2018	600	—
6 % Senior Subordinated Notes due 2020	695	—
5¾% Senior Notes due 2022	750	—
5 % Senior Notes due 2024	1,000	—
	$3,045	$649

We consider our interest rate exposure to be minimal because 82% of our obligations were at fixed rates as of December 31, 2013, and our variable rate debt was at interest rates of 2% or less. In early February 2014, we closed the sale of our Malaysian business and paid in full amounts previously outstanding under our revolving credit facility and money market lines of credit.

Foreign Currency Exchange Rates

The functional currency for all of our foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country’s functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at December 31, 2013.

Item 8. Financial Statements and Supplementary Data

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AND SUPPLEMENTARY INFORMATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our Company's management, including the Chief Executive Officer and the Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our internal control over financial reporting includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

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

Based on our evaluation under the framework in Internal Control — Integrated Framework (1992), the management of our Company concluded that our internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

Lee K. Boothby
President and Chief Executive Officer

Lawrence S. Massaro
Executive Vice President and Chief Financial Officer

The Woodlands, Texas
February 27, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Newfield Exploration Company:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, of comprehensive income, of stockholders’ equity and of cash flows present fairly, in all material respects, the financial position of Newfield Exploration Company and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

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

Houston, Texas
February 27, 2014

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEET
(In millions, except per share data)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$95	$88
Restricted cash	90	—
Accounts receivable	474	452
Inventories	163	132
Derivative assets	—	125
Deferred taxes	22	—
Other current assets	57	69
Total current assets	901	866
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties $1,300 and $1,485 were excluded from amortization at December 31, 2013 and 2012, respectively)	16,650	14,346
Less — accumulated depreciation, depletion and amortization	(8,375)	(7,444)
Total property and equipment, net	8,275	6,902
Derivative assets	26	17
Long-term investments	63	58
Deferred taxes	19	24
Other assets	37	45
Total assets	$9,321	$7,912
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$76	$69
Accrued liabilities	978	801
Deferred liabilities	90	—
Advances from joint owners	30	31
Asset retirement obligations	54	10
Derivative liabilities	62	6
Deferred taxes	—	42
Total current liabilities	1,290	959
Other liabilities	38	47
Derivative liabilities	—	15
Long-term debt	3,694	3,045
Asset retirement obligations	201	132
Deferred taxes	1,142	934
Total long-term liabilities	5,075	4,173
Commitments and contingencies (Note 14)		
Stockholders' equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)	—	—
Common stock ($0.01 par value, 200,000,000 shares authorized at December 31, 2013 and 2012; 136,682,631 and 136,530,907 shares issued at December 31, 2013 and 2012, respectively)	1	1
Additional paid-in capital	1,539	1,522
	(13)	(36)

Treasury stock (at cost, 460,914 and 1,216,591 shares at December 31, 2013 and 2012, respectively)		
Accumulated other comprehensive gain (loss)	2	(7)
Retained earnings	1,427	1,300
Total stockholders' equity	2,956	2,780
Total liabilities and stockholders' equity	$9,321	$7,912

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF OPERATIONS
(In millions, except per share data)

	Year Ended December 31,		
	2013	2012	2011
Oil, gas and NGL revenues	$1,789	$1,476	$1,742
Operating expenses:			
Lease operating	413	406	358
Production and other taxes	67	67	68
Depreciation, depletion and amortization	668	683	621
General and administrative	219	211	180
Ceiling test impairment	—	1,488	—
Other	3	15	—
Total operating expenses	1,370	2,870	1,227
Income (loss) from operations	419	(1,394)	515
Other income (expense):			
Interest expense	(205)	(205)	(175)
Capitalized interest	53	68	82
Commodity derivative income (expense)	(97)	120	195
Other, net	—	(2)	2
Total other income (expense)	(249)	(19)	104
Income (loss) before income taxes	170	(1,413)	619
Income tax provision (benefit):			
Current	(4)	2	17
Deferred	66	(513)	201
Total income tax provision (benefit)	62	(511)	218
Income (loss) from continuing operations	108	(902)	401
Income (loss) from discontinued operations, net of tax	39	(282)	138
Net income (loss)	$147	$(1,184)	$539
Earnings (loss) per share:			
Basic:			
Income (loss) from continuing operations	$0.80	$(6.70)	$3.00
Income (loss) from discontinued operations	0.14	(2.10)	1.03
Basic earnings (loss) per share	$0.94	$(8.80)	$4.03
Diluted:			
Income (loss) from continuing operations	$0.80	$(6.70)	$2.97
Income (loss) from discontinued operations	0.14	(2.10)	1.02
Diluted earnings (loss) per share	$0.94	$(8.80)	$3.99
Weighted-average number of shares outstanding for basic earnings (loss) per share	135	135	134
	136	135	135

Weighted-average number of shares outstanding for diluted
earnings
(loss) per share

The accompanying notes to consolidated financial statements are an integral part of this statement.
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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2013	2012	2011
Net income (loss)	$147	$(1,184)	$539
Other comprehensive income (loss):			
Unrealized gain (loss) on investments, net of tax of ($3) for the year ended December 31, 2013, and ($1) for the years ended December 31, 2012 and 2011	7	3	3
Unrealized gain (loss) on post-retirement benefits, net of tax of ($1) for the year ended December 31, 2013	2	—	(1)
Other comprehensive income (loss), net of tax	9	3	2
Comprehensive income (loss)	$156	$(1,181)	$541

The accompanying notes to consolidated financial statements are an integral part of this statement.
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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In millions)

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance, December 31, 2010	135.9	$1	(1.7)	$(41)	$ 1,450	$ 1,945	$ (12)	$ 3,343
Issuances of common stock	0.5	—			13			13
Stock-based compensation					37			37
Treasury stock, net			—	(9)	(5)			(14)
Net income						539		539
Other comprehensive income, net of tax							2	2
Balance, December 31, 2011	136.4	1	(1.7)	(50)	1,495	2,484	(10)	3,920
Issuances of common stock	0.1	—			2			2
Stock-based compensation					46			46
Treasury stock, net			0.5	14	(21)			(7)
Net loss						(1,184)		(1,184)
Other comprehensive income, net of tax							3	3
Balance, December 31, 2012	136.5	1	(1.2)	(36)	1,522	1,300	(7)	2,780
Issuances of common stock	0.2	—			1			1
Stock-based compensation					45			45
Treasury stock, net			0.7	23	(29)			(6)
Net income						147		147
Other comprehensive income, net of tax							9	9
Repurchase of preferred shares of subsidiary						(20)		(20)
Balance, December 31, 2013	136.7	$1	(0.5)	$(13)	$ 1,539	$ 1,427	$ 2	$ 2,956

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2013	2012	2011
Cash flows from operating activities:			
Net income (loss)	$147	$(1,184)	$539
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	930	955	767
Deferred tax provision	143	1	208
Stock-based compensation	43	35	29
Commodity derivative (income) expense	97	(120)	(195)
Cash receipts on derivative settlements, net	60	135	195
Ceiling test impairment	—	1,488	—
Other non-cash charges	14	19	6
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(62)	(70)	(24)
(Increase) decrease in inventories	(11)	(35)	(16)
(Increase) decrease in other current assets	12	5	(12)
(Increase) decrease in other assets	6	7	(7)
Increase (decrease) in accounts payable and accrued liabilities	74	(77)	120
Increase (decrease) in advances from joint owners	(1)	(14)	(6)
Increase (decrease) in other liabilities	(7)	2	(15)
Net cash provided by operating activities	1,445	1,147	1,589
Cash flows from investing activities:			
Additions to oil and gas properties	(1,987)	(1,758)	(2,311)
Acquisitions of oil and gas properties	(72)	(9)	(304)
Proceeds from sales of oil and gas properties	36	630	406
Additions to furniture, fixtures and equipment	(36)	(22)	(29)
Redemptions of investments	1	—	2
Net cash used in investing activities	(2,058)	(1,159)	(2,236)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	3,263	2,844	3,958
Repayments of borrowings under credit arrangements	(2,614)	(2,930)	(4,007)
Proceeds from issuance of senior notes	—	1,000	750
Debt issue costs	(4)	(10)	(16)
Repayment of senior subordinated notes	—	(875)	—
Proceeds from issuances of common stock	1	2	13
Repurchase of preferred shares of subsidiary	(20)	—	—
Purchases of treasury stock, net	(6)	(7)	(14)
Net cash provided by financing activities	620	24	684
Increase (decrease) in cash and cash equivalents	7	12	37
Cash and cash equivalents, beginning of period	88	76	39
Cash and cash equivalents, end of period	$95	$88	$76

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids (NGLs). Our principal areas of operation include the Mid-Continent, the Rocky Mountains and the onshore Gulf Coast regions of North America.

Our consolidated financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and natural gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to “Newfield,” “we,” “us,” “our” or the “Company” are to Newfield Exploration Company and its subsidiaries.

Discontinued Operations

Our businesses in Malaysia and China were classified as held-for-sale in the second quarter of 2013. Accordingly, the results of our international operations are reflected separately as discontinued operations in the consolidated statement of operations on a line immediately after "Income (loss) from continuing operations." See Note 3, "Discontinued Operations," for additional disclosures. For information regarding the sale of our Malaysia business, see Note 17, "Subsequent Events." These financial statements and notes are inclusive of our international operations unless otherwise noted.

Dependence on Commodity Prices

As an independent oil and natural gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for oil, natural gas and NGLs. Historically, the energy markets have been very volatile, and there can be no assurance that commodity prices will not be subject to wide fluctuations in the future. A substantial or extended decline in commodity prices could have a material adverse effect on our financial position, results of operations, cash flows, access to capital and on the quantities of oil, natural gas and NGL reserves that we can economically produce.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities; disclosure of contingent assets and liabilities at the date of the financial statements; the reported amounts of revenues and expenses during the reporting period; and the quantities and values of proved oil, natural gas and NGL reserves used in calculating depletion and assessing impairment of our oil and gas properties. Actual results could differ significantly from these estimates. Our most significant financial estimates are associated with our estimated proved oil, natural gas and NGL reserves and the fair value of our derivative positions.

Reclassifications and Out-of-Period Adjustments

Certain reclassifications have been made to prior years’ reported amounts in order to conform to the current year presentation. These reclassifications, including those related to our discontinued operations disclosed in Note 3, "Discontinued Operations," did not impact our net income (loss), stockholders’ equity or cash flows.

The Company's production and other taxes for continuing operations for the year ended December 31, 2013, were reduced by approximately $8 million in the fourth quarter due to a prior period adjustment related to our 2012 and prior ad valorem tax accrual to reflect the actual amounts payable at December 31, 2013. The Company's general and administrative expenses for the year ended December 31, 2013, were reduced by approximately $8 million due to a prior period adjustment related to our 2012 bonus accrual to reflect actual amounts approved and paid in the first quarter of 2013. The Company’s discontinued operations deferred tax expense for the year ended December 31, 2013 was increased by approximately $15 million due to prior period adjustments related to our 2012 repatriation of international earnings and a valuation allowance on a Malaysian deferred tax asset. The Company believes these correcting adjustments in the fourth quarter of 2013 were not material to its prior consolidated financial statements or its quarterly or annual results for the period ended December 31, 2013.

Revenue Recognition

Substantially all of our oil, natural gas and NGLs are sold at market-based prices to a variety of purchasers under short-term contracts (less than 12 months). We also have long-term contracts in the Uinta Basin at market-based prices. We record revenue when we deliver our production to the customer and collectability is reasonably assured. Revenues from the production of oil, natural gas and NGLs on properties in which we have joint ownership are recorded under the sales method. Under the sales method, the Company and other joint owners may sell more or less than their entitled share of production. Should the Company's excess sales exceed our share of estimated remaining recoverable reserves, a liability is recorded. Differences between sales and our entitled share of production are not significant.

Foreign Currency

The functional currency for all of our foreign operations is the U.S. dollar. Gains and losses incurred on transactions in a currency other than a country's functional currency are recorded under the caption "Other income (expense) — Other, net" on our consolidated statement of operations.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with a maturity of three months or less when acquired and are stated at cost, which approximates fair value. We invest cash in excess of near-term capital and operating requirements in U.S. Treasury Notes, Eurodollar time deposits and money market funds, which are classified as cash and cash equivalents on our consolidated balance sheet.

Restricted Cash and Deferred Liabilities

Restricted cash and the associated deferred liability on our consolidated balance sheet at December 31, 2013, represent a deposit received in 2013 on the pending sale of our Malaysian business. Amounts are contractually restricted until the transaction closes. See Note 17, "Subsequent Events," for further discussion about the close of the sale of the Malaysian business in early February 2014.

Investments

Investments consist of debt and equity securities, as well as auction rate securities, a majority of which are classified as "available-for-sale" and stated at fair value. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component within the consolidated statement of comprehensive income. Realized gains or losses are computed based on specific identification of the securities sold. We regularly assess our investments for impairment and consider any impairment to be other than temporary if we intend to sell the security, it is more likely than not that we will be required to sell the security, or we do not expect to recover our cost of the security. We realized interest income and net gains on our investment securities in 2013, 2012 and 2011 of $3 million, $3 million and $2 million, respectively.

Allowance for Doubtful Accounts

We routinely assess the recoverability of all material trade and other receivables to determine their collectability. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, our oil and gas receivables are collected within 45 to 60 days of production. We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated.

Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and natural gas operations and oil produced but not sold in our offshore operations in Malaysia and China. See Note 3, "Discontinued Operations" for details on our international crude oil inventory. Tubular goods and well equipment inventories are carried at the lower of cost or market. At December 31, 2012, we wrote down subsea wellhead inventory that was not included in the sale of our Gulf of Mexico assets. The writedown of $8 million is included in “Operating expenses — Other” on our consolidated statement of operations.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized approximately $145 million, $123 million and $113 million of internal costs in 2013, 2012 and 2011, respectively. Interest expense related to unproved properties also is capitalized into oil and gas properties.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the reduction would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized.

Capitalized costs and estimated future development costs are amortized using a unit-of-production method based on proved reserves associated with the applicable cost center. For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of the unamortized cost or the cost center ceiling. A particular cost center ceiling is equal to the sum of:

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using oil, natural gas and NGL reserve estimation requirements, which require use of the unweighted average first-day-of-the-month commodity prices for the prior 12 months, adjusted for market differentials (SEC pricing), applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus
- the cost of properties not included in the costs being amortized, if any; less
- related income tax effects.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, a ceiling test writedown reduces earnings and stockholders' equity in the period of occurrence and, holding other factors constant, results in lower depreciation, depletion and amortization expense in future periods.

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil, natural gas and NGL prices decrease significantly for a prolonged period of time or if we have substantial downward revisions in our estimated proved reserves. At December 31, 2013, the ceiling value of our reserves was calculated based upon SEC pricing of $3.67 per MMBtu for natural gas and $96.82 per barrel for oil. Using these prices, the cost center ceiling with respect to our domestic full cost pool exceeded the net capitalized costs. As such, no ceiling test writedown was required at December 31, 2013. If there are declines in SEC pricing of oil and natural gas subsequent to December 31, 2013, we may be required to record a ceiling test writedown in future periods.

At December 31, 2012, the ceiling value of our reserves was calculated based upon SEC pricing of $2.76 per MMBtu for natural gas and $94.84 per barrel for oil. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties exceeded the ceiling amount by approximately $1.5 billion ($948 million, after-tax).

At December 31, 2011, the ceiling value of our reserves was calculated based upon SEC pricing of $4.12 per MMBtu for natural gas and $96.13 per barrel for oil. Using these prices, the cost center ceiling with respect to our domestic full cost pool exceeded the net capitalized costs. As such, no ceiling test writedown was required at December 31, 2011.

See Note 4, “Oil and Gas Assets,” for a detailed discussion regarding our acquisition and sales transactions during 2013, 2012 and 2011.

Other Property and Equipment

Furniture, fixtures and equipment are recorded at cost and are depreciated using the straight-line method over their estimated useful lives, which range from three to seven years. Gathering systems and equipment are recorded at cost and depreciated using the straight-line method over their estimated useful lives of 25 years.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Segment Reporting

Our continuing operations are comprised of a single business segment, the domestic exploration, development and production of oil and natural gas. Prior to classifying our international businesses as held-for-sale and discontinued operations, we reported business segments for Malaysia and China.

Accounting for Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the present value of the asset retirement cost in oil and gas properties in the period in which the ARO is incurred. Settlements include payments made to satisfy the AROs, as well as transfer of the ARO to purchasers of our divested properties.

In general, the amount of an ARO and the costs capitalized will equal the estimated future cost to satisfy the abandonment obligation assuming normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our Company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds, and the original capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. Both the accretion and the depreciation are included in depreciation, depletion and amortization expense on our consolidated statement of operations.

The change in our ARO for continuing operations for each of the three years ended December 31, is set forth below:

	2013	2012	2011
	(In millions)		
Balance at January 1	$100	$106	$96
Accretion expense	8	8	8
Additions	12	20	5
Revisions	8	12	3
Settlements[1]	(8)	(46)	(6)
Balance at December 31	120	100	106
Less: Current portion of ARO at December 31	(5)	(5)	(4)
Total long-term ARO at December 31	$115	$95	$102

(1) For the year ended December 31, 2012, settlements include $28 million related to the sale of our Gulf of Mexico assets. See Note 4, “Oil and Gas Assets.”

Contingencies

We are subject to legal proceedings, claims, liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated. See Note 14, “Commitments and Contingencies,” for a more detailed discussion regarding our contingencies.

Environmental Matters

Environmental costs that relate to current operations are expensed as incurred. Remediation costs that relate to an existing condition caused by past operations are accrued when it is probable that those costs will be incurred and can be reasonably estimated based upon evaluations of currently available facts related to each site.

Income Taxes

We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

As of December 31, 2013, we did not have a liability for uncertain tax positions, and as such, we did not accrue related interest or penalties. The tax years 2010-2013 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

Stock-Based Compensation

We apply a fair value-based method of accounting for stock-based compensation which requires recognition in the financial statements of the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. For equity-based compensation awards, compensation expense is based on the fair value on the grant or modification date and is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option-pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted stock and restricted stock units. We also have cash-settled restricted stock units as well as a Stockholder Value Appreciation Program that are accounted for under the liability method which requires us to recognize the fair value of each award based on the underlying share price at the end of each period. See Note 11, “Stock-Based Compensation,” for a full discussion of our stock-based compensation.

Concentration of Credit Risk

We operate a substantial portion of our oil and gas properties. As the operator of a property, we make full payment for costs associated with the property and seek reimbursement from the other working interest owners in the property for their share of those costs. Our joint interest partners consist primarily of independent oil and gas producers. If the oil and gas exploration and production industry in general was adversely affected, the ability of our joint interest partners to reimburse us could be adversely affected.

The purchasers of our oil, gas and NGL production consist primarily of independent marketers, major oil and gas companies, refiners and gas pipeline companies. We perform credit evaluations of the purchasers of our production and monitor their financial condition on an ongoing basis. Based on our evaluations and monitoring, we obtain cash escrows, letters of credit or parental guarantees from some purchasers. Historically, we have sold our oil, gas and NGLs to several purchasers.

All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The counterparties for all of our hedging transactions have an “investment grade” credit rating. We monitor the credit ratings of our hedging counterparties on an ongoing basis. Although we have entered into hedging contracts with multiple counterparties to mitigate our exposure to any individual counterparty, if any of our counterparties were to default on its obligations to us under the hedging contracts or seek bankruptcy protection, it could have a material adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened and fewer counterparties may participate in hedging transactions, which could result in greater concentration of our exposure to any one counterparty or a larger percentage of our future production being subject to commodity price changes. At December 31, 2013, nine of our 15 counterparties accounted for approximately 85% of our estimated future hedged production, with no single counterparty accounting for more than

15% of that production. A portion of our derivative instruments are with lenders under our credit facility. Our credit facility, senior notes, senior subordinated notes and substantially all of our derivative instruments contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

Major Customers

Sunoco Logistics Partners Operations GP LLC, Royal Dutch Shell plc and Tesoro Corporation accounted for 13%, 12% and 11% respectively, of our total revenues in 2013. During 2012, Royal Dutch Shell plc, Tesoro Corporation and Big West Oil LLC accounted for 14%, 14% and 10%, respectively, of our total revenues. During 2011, sales of our oil and gas production to Royal Dutch Shell plc and Tesoro Corporation accounted for 12% and 11%, respectively, of our total revenues. We believe that the loss of Sunoco Logistics Partners Operations GP LLC or Royal Dutch Shell plc would not have a material adverse effect on us because alternative purchasers are readily available. An extended loss of Tesoro Corporation or any of our other large purchasers of our Monument Butte field oil production could have a material adverse effect on us because there are limited

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

purchasers of the black and yellow wax crude oil, which we produce from this field. Due to the higher paraffin content of this production, it must remain heated during shipping, so it cannot be transported in conventional pipelines, and there is limited refining capacity for it in the vicinity of our production. In poor economic environments and tight financial markets, there is an increased risk that the current purchasers of our production may fail to satisfy their obligations to us under our crude oil purchase contracts. We cannot guarantee that we will be able to continue to sell to these purchasers or that similar substitute arrangements could be made for sales of our black and yellow wax crude oil with other purchasers if desired.

Derivative Financial Instruments

Our derivative instruments are recorded on the consolidated balance sheet at fair value as either an asset or a liability with changes in fair value recognized currently in earnings. While all of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production, we have elected not to designate our derivative instruments as accounting hedges under the accounting guidance. We periodically utilize derivatives to manage our exposure to variable interest rates.

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities. See Note 5, “Derivative Financial Instruments,” for a more detailed discussion of our derivative activities.

Offsetting Assets and Liabilities

Our derivative financial instruments are subject to master netting arrangements and are reflected on our consolidated balance sheet accordingly. See Note 5, "Derivative Financial Instruments," for details regarding the gross amounts, as well as the impact of our netting arrangements on our net derivative position. We only offset assets and liabilities in relation to our derivative financial instruments.

Accumulated Other Comprehensive Income

At December 31, 2012, accumulated other comprehensive income (“AOCI”) included unrealized losses related to auction rate securities that were deemed to be temporary as the Company had the intent and ability to hold the securities to maturity. As of December 31, 2013, the Company changed its intention and will likely sell the securities for a loss during 2014. As a result, the losses previously accumulated in AOCI related to these securities have been transferred and recognized in the consolidated statement of operations for the year ended December 31, 2013. The change in AOCI for the indicated periods is set forth below:

	Unrealized Gains / (Losses) in Accumulated Other Comprehensive Income		
	Available-for-Sale Securities	Post-Retirement Benefits	Total
	(In millions, net of tax)		
Balance at January 1, 2011	$(12)	$—	$(12)
Current period other comprehensive income (loss)	3	(1)	2
Balance at December 31, 2011	(9)	(1)	(10)
Current period other comprehensive income (loss)	3	—	3
Balance at December 31, 2012	(6)	(1)	(7)
Other comprehensive income (loss) before reclassifications	3	2	5
	4	—	4

Amounts reclassified from accumulated other comprehensive income			
Net current period other comprehensive income (loss)	7	2	9
Balance at December 31, 2013	$1	$1	$2

New Accounting Requirements

In February 2013, the FASB issued guidance regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The guidance is effective for interim and annual periods beginning after December 15, 2012. We adopted the guidance in the quarter ended March 31, 2013. Adoption of the new reporting guidance did not have a material impact on our financial position or results of operations.

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance requires disclosure of gross information and net information about instruments and transactions eligible for offset arrangement. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. We adopted the guidance in the quarter ended March 31, 2013. Adoption of the additional disclosures regarding offsetting assets and liabilities did not have a material impact on our financial position or results of operations.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income, less any applicable adjustments, (the numerator) by the weighted-average number of shares of common stock (excluding unvested restricted stock and restricted stock units) outstanding during the period (the denominator). Diluted EPS incorporates the dilutive impact of outstanding stock options and unvested restricted stock and restricted stock units (using the treasury stock method). Under the treasury stock method, the amount the employee must pay for exercising stock options, the amount of unrecognized compensation expense related to unvested stock-based compensation grants and the amount of excess tax benefits that would be recorded when the award becomes deductible are assumed to be used to repurchase shares. See Note 11, “Stock-Based Compensation.”

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following is the calculation of basic and diluted weighted-average shares outstanding and EPS for the indicated years:

	2013	2012	2011
	(In millions, except per share data)		
Income (numerator):			
Income (loss) from continuing operations	$108	$(902)	$401
Income (loss) from discontinued operations, net of tax	39	(282)	138
Net income (loss)	147	(1,184)	539
Repurchase of preferred shares of subsidiary [3]	(20)	—	—
Net income (loss) attributable to common shareholders	$127	$(1,184)	$539
Weighted-average shares (denominator):			
Weighted-average shares — basic	135	135	134
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period [1][2]	1	—	1
Weighted-average shares — diluted	136	135	135
Earnings (loss) per share:			
Basic:			
Income (loss) from continuing operations	$0.80	$(6.70)	$3.00
Income (loss) from discontinued operations before preferred share repurchase	0.29	(2.10)	1.03
Repurchase of preferred shares of subsidiary [3]	(0.15)	—	—
Income (loss) from discontinued operations	0.14	(2.10)	1.03
Basic earnings (loss) per share	$0.94	$(8.80)	$4.03
Diluted:			
Income (loss) from continuing operations	$0.80	$(6.70)	$2.97
Income (loss) from discontinued operations before preferred share repurchase	0.29	(2.10)	1.02
Repurchase of preferred shares of subsidiary [3]	(0.15)	—	—
Income (loss) from discontinued operations	0.14	(2.10)	1.02
Diluted earnings (loss) per share	$0.94	$(8.80)	$3.99

(1) Excludes 4.0 million and 1.4 million shares of unvested restricted stock or restricted stock units and stock options for the years ended December 31, 2013 and 2011, respectively, because including the effect would have been anti-dilutive.

(2) The effect of unvested restricted stock or restricted stock units and stock options has not been included in the calculation of shares outstanding for diluted EPS for the year ended December 31, 2012, as their effect would have been anti-dilutive. Had we recognized income from continuing operations for that year, incremental shares attributable to the assumed vesting of unvested restricted stock and restricted stock units and the assumed exercise of outstanding stock options would have increased diluted weighted-averages shares outstanding by 0.7 million shares for the year ended December 31, 2012.

(3) The numerator includes an adjustment of $20 million related to the repurchase of preferred shares of a now wholly-owned subsidiary, which reduces net income (loss) for purposes of earnings per share for the year ended December 31, 2013. The subsidiary is part of our discontinued operations. See Note 16, "Related Party

Transaction," for additional information.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

3. Discontinued Operations:

In February 2013, we announced our decision to explore strategic alternatives for our international businesses. In accordance with specific accounting requirements, we met the criteria to classify our international businesses as held-for-sale and discontinued operations during the second quarter of 2013. As a result, the historical results of operations for our Malaysia and China businesses are reflected in our financial statements as "discontinued operations."

Malaysia Update

As discussed in Note 17, "Subsequent Events," we closed the sale of our Malaysia business on February 10, 2014.

China Update

In August of 2013, during the installation of the LF-7 topside facilities by a third-party contractor, a hydraulic jacking system malfunctioned and the installation was suspended. The installation of the facility has been delayed and the potential cost and timing for the reinstallation is uncertain at this time. As a result of this incident, the timing of the China divestiture has been delayed. The Company continues to actively market its China business. After reevaluating the criteria to be classified as discontinued operations, we believe that our China operations continue to meet the "held for sale" criteria and therefore remain in discontinued operations as of December 31, 2013. We will continue to monitor the facts and circumstances surrounding the completion of the production facilities and sale of our China operations on a quarterly basis.

Financial Results of Discontinued Operations

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Oil and gas revenues [1]	$891	$1,092	$729
Operating expenses	689	664	508
Income from discontinued operations	202	428	221
Other income (expense)	4	(3)	—
Income from discontinued operations before income taxes	206	425	221
Income tax provision (benefit):			
Current	90	193	76
Deferred	77	514	7
Total income tax provision (benefit)	167	707	83
Income (loss) from discontinued operations, net of tax	$39	$(282)	$138

(1) Certain payments to foreign governments made on our behalf that are part of the revenue process are recorded as a reduction of the related oil and gas revenues.

Income Taxes

The effective tax rates for our discontinued operations for the year ended December 31, 2013, 2012 and 2011 were 81%, 166% and 37%, respectively. Historically, our international effective tax rate was approximately 37%. However, the effective tax rates for 2013 and 2012 were affected by our decision to repatriate earnings from our foreign operations, which resulted in net income of our international businesses being taxed both in the U.S. and the local country, and the recording of a valuation allowance related to our deferred tax asset in Malaysia.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Assets and Liabilities in the Consolidated Balance Sheet from Discontinued Operations

	December 31, 2013	2012
	(In millions)	
Current assets:		
Cash and cash equivalents	$84	$76
Accounts receivable	200	207
Inventories	130	91
Other current assets	33	31
Total current assets	447	405
Noncurrent assets:		
Oil and gas properties, net of accumulated depreciation, depletion and amortization of $1,121 and $843 as of December 31, 2013 and 2012, respectively	989	781
Deferred taxes	19	24
Other assets	4	4
Total noncurrent assets	1,012	809
Total assets	$1,459	$1,214
Current liabilities:		
Accounts payable	$38	$50
Accrued liabilities	324	269
Asset retirement obligations	49	5
Other current liabilities	18	16
Total current liabilities	429	340
Noncurrent liabilities:		
Asset retirement obligations	86	37
Deferred taxes	129	41
Other liabilities	11	24
Total noncurrent liabilities	226	102
Total liabilities	$655	$442

Crude Oil Inventories

Substantially all of the crude oil from our offshore operations in Malaysia and China is produced into floating production, storage and off-loading vessels (FPSOs) or onshore storage terminals and “lifted” and sold periodically as barge quantities are accumulated. The product inventory from our international operations consisted of approximately 1.1 million barrels and 0.7 million barrels of crude oil valued at cost of $90 million and $64 million at December 31, 2013 and 2012, respectively, and are included in the "Inventories" line item in the preceding table and our consolidated balance sheet. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depletion expense.

Oil and Gas Properties

At December 31, 2013, the oil and gas properties associated with our discontinued operations included $115 million not subject to amortization, comprised of $45 million incurred prior to 2011, $2 million incurred in 2011, $24 million incurred in 2012 and $44 million incurred in 2013.

At December 31, 2013, we performed a fair value assessment of our Malaysia and China discontinued operations, noting no indication of impairment based on the current carrying value.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

During 2012, when our Malaysia and China businesses were reported as continuing operations, we performed a ceiling test for each full cost pool. The ceiling value of our reserves was calculated based upon SEC pricing of $2.76 per MMBtu for natural gas and $94.84 per barrel for oil. At December 31, 2011, the ceiling value of our reserves was calculated based upon SEC pricing of $4.12 per MMBtu for natural gas and $96.13 per barrel for oil. Using these prices, the cost center ceilings with respect to our Malaysia and China full cost pools exceeded the net capitalized costs of the respective cost centers at December 31, 2012 and December 31, 2011, and as such, no ceiling test writedowns were required.

The change in our ARO for discontinued operations for each of the three years ended December 31, is set forth below:

	2013	2012	2011
	(In millions)		
Balance at January 1	$42	$39	$12
Accretion expense	3	3	2
Additions	4	4	29
Revisions	101	—	—
Settlements	(15)	(4)	(4)
Balance at December 31	135	42	39
Less: Current portion of ARO at December 31	(49)	(5)	(6)
Total long-term ARO at December 31	$86	$37	$33

4. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at December 31:

	2013	2012
	(In millions)	
Oil and gas properties:		
Subject to amortization	$15,107	$12,647
Not subject to amortization	1,300	1,485
Gross oil and gas properties	16,407	14,132
Accumulated depreciation, depletion and amortization	(8,306)	(7,378)
Net oil and gas properties	8,101	6,754
Other property and equipment:		
Furniture, fixtures and equipment	139	141
Gathering systems and equipment	104	73
Accumulated depreciation and amortization	(69)	(66)
Net other property and equipment	174	148
Total property and equipment, net	$8,275	$6,902

Oil and gas properties not subject to amortization represent investments in unproved properties and major development projects in which we own an interest. These unproved property costs include unevaluated leasehold acreage, geological and geophysical data costs associated with leasehold or drilling interests, costs associated with wells in progress at December 31 and capitalized internal costs. We exclude these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. Unproved property costs are grouped by major prospect area where individual property costs are not significant and are assessed individually when individual costs are significant. Costs associated with wells in progress are transferred to the amortization base upon the determination of whether proved reserves can be assigned to the properties, which is generally based on drilling results. All other costs excluded from the amortization base are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the amortization base or a charge is made against earnings for international operations if a reserve base has not yet been established.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following is a summary of our oil and gas properties not subject to amortization as of December 31, 2013. At December 31, 2013, approximately 82% of our oil and gas properties not subject to amortization were associated with unconventional resource plays. Because of the size of our unconventional resource plays, the entire evaluation can take significantly longer than four years. However, we believe that our evaluation activities related to substantially all of our conventional properties not subject to amortization will be completed within four years.

	Costs Incurred In				
	2013	2012	2011	2010 and Prior	Total
	(In millions)				
Acquisition costs	$206	$114	$188	$ 300	$808
Exploration costs	175	21	9	35	240
Development costs	13	31	25	—	69
Fee mineral interests	1	—	—	23	24
Capitalized interest	53	68	38	—	159
Total oil and gas properties not subject to amortization	$448	$234	$260	$ 358	$1,300

Gulf of Mexico Asset Sale

In October 2012, we closed the sale of our remaining assets in the Gulf of Mexico to W&T Offshore, Inc. for approximately $208 million, subject to customary post-closing adjustments. The sale of our remaining assets in the Gulf of Mexico did not significantly alter the relationship between capitalized costs and proved reserves, and as such, all proceeds were recorded as adjustments to our domestic full cost pool with no gain or loss recognized. These consolidated financial statements include the results of our Gulf of Mexico operations through the date of sale.

Uinta Basin Asset Acquisitions

In May 2011, we closed two transactions to acquire assets in the Uinta basin of Utah for a total of approximately $303 million. The assets include approximately 65,000 net acres, which are largely undeveloped and located north of our Greater Monument Butte Unit.

Other Asset Acquisitions and Sales

During 2013, 2012 and 2011, we acquired various other oil and gas properties for approximately $72 million, $9 million and $1 million, respectively, and sold certain oil and gas properties for proceeds of approximately $36 million, $630 million(includes Gulf of Mexico asset sale discussed above) and $406 million, respectively. The cash flows and results of operations for the assets included in a sale are included in our consolidated financial statements up to the date of sale. All of the proceeds associated with our asset sales were recorded as adjustments to our domestic full cost pool.

5. Derivative Financial Instruments:

Commodity Derivative Instruments

We utilize the following derivative strategies, which consist of either a single derivative instrument or a combination of instruments, to hedge against the variability in cash flows associated with the forecasted sale of our future oil and natural gas production domestically.

- Fixed-price swaps. With respect to a swap position, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap strike price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap strike price.
- Collars (combination of purchased put options (floor) and sold call options (ceiling)). For a collar position, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

strike price while we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling strike price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor strike price and equal to or less than the ceiling strike price.

- Fixed-price swaps with sold puts. A swap with a sold put position consists of a standard swap position plus a put sold by us with a strike price below the associated fixed-price swap. This structure enables us to increase the fixed-price swap with the value received through the sale of the put. If the settlement price for any settlement period falls equal to or below the put strike price, then we will only receive the difference between the swap price and the put strike price. If the settlement price is greater than the put strike price, the result is the same as it would have been with a standard swap only.
- Collars with sold puts. A collar with a sold put position consists of a standard collar position plus a put sold by us with a strike price below the floor strike price of the collar. This structure enables us to improve the collar strike prices with the value received through the sale of the additional put. If the settlement price for any settlement period falls equal to or below the additional put strike price, then we will receive the difference between the floor strike price and the additional put strike price. If the settlement price is greater than the additional put strike price, the result is the same as it would have been with a standard collar only.

While the use of these derivative instruments limits the downside risk of adverse commodity price movements, their use also may limit future income from favorable commodity price movements. For discussion of the accounting policies associated with our derivative financial instruments (including the offsetting of derivative assets and liabilities), see Note 1, "Organization and Summary of Significant Accounting Policies."

Our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, estimated volatility, non-performance risk adjustments using credit default swaps and time to maturity. The calculation of the fair value of collars and sold puts requires the use of an option-pricing model. See Note 8, “Fair Value Measurements.”

At December 31, 2013, we had outstanding positions with respect to our future production as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu				
				Collars		
Period and Type of Instrument	Volume in MMMBtus	Swaps (Weighted Average)	Sold Puts(Weighted Average)	Floors(Weighted Average)	Ceilings(Weighted Average)	Estimated Fair Value Asset (Liability) (In millions)
January 2014 — March 2014						
Fixed-price swaps	21,150	$3.98	—	—	—	$(6)
Collars	5,850	—	—	$3.75	$ 4.62	(1)
April 2014 — June 2014						
Fixed-price swaps	21,385	3.98	—	—	—	(3)
Collars	5,915	—	—	3.75	4.62	—
July 2014 — September 2014						

Fixed-price swaps	21,620	3.98	—	—	—	(4	)
Collars	5,980	—	—	3.75	4.62	—	
October 2014 — December 2014							
Fixed-price swaps	21,620	3.98	—	—	—	(5	)
Collars	5,980	—	—	3.75	4.62	(1	)
January 2015 — December 2015							
Fixed-price swaps	49,275	4.28	—	—	—	7	
Collars	38,325	—	—	3.93	4.74	2	
						$(11	)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Crude Oil

Period and Type of Instrument	Volume in MBbls	NYMEX Contract Price Per Bbl Swaps (Weighted Average)	Sold Puts (Weighted Average)	Collars Floors (Weighted Average)	Ceilings (Weighted Average)	Estimated Fair Value Asset (Liability) (In millions)
January 2014 — March 2014						
Fixed-price swaps	1,350	$89.60	—	—	—	$(12)
Fixed-price swaps with sold puts	1,440	95.16	$75.00	—	—	(4)
Collars with sold puts	540	—	75.83	$90.83	$102.93	(1)
April 2014 — June 2014						
Fixed-price swaps	1,729	90.07	—	—	—	(12)
Fixed-price swaps with sold puts	1,456	95.16	75.00	—	—	(3)
Collars with sold puts	546	—	75.83	90.83	102.93	—
July 2014 — September 2014						
Fixed-price swaps	1,932	89.86	—	—	—	(9)
Fixed-price swaps with sold puts	1,472	95.16	75.00	—	—	—
Collars with sold puts	552	—	75.83	90.83	102.93	1
October 2014 — December 2014						
Fixed-price swaps	2,116	89.95	—	—	—	(5)
Fixed-price swaps with sold puts	1,472	95.16	75.00	—	—	2
Collars with sold puts	552	—	75.83	90.83	102.93	1
January 2015 — December 2015						
Fixed-price swaps	6,567	90.39	—	—	—	14
Fixed-price swaps with sold puts	4,567	90.03	68.20	—	—	3
						$(25)

Additional Disclosures about Derivative Instruments and Hedging Activities

We had derivative financial instruments recorded in our consolidated balance sheet as assets (liabilities) at their respective estimated fair value, as set forth below.

December 31, 2013	Derivative Assets Gross Fair Value (In millions)	Offset in Balance Sheet	Balance Sheet Location Current	Noncurrent	Derivative Liabilities Gross Fair Value (In millions)	Offset in Balance Sheet	Balance Sheet Location Current	Noncurrent
Natural gas positions	$11	$(2)	$—	$9	$(22)	$2	$(20)	$—
Oil positions	26	(9)	—	17	(51)	9	(42)	—
Total	$37	$(11)	$—	$26	$(73)	$11	$(62)	$—

December 31, 2012								
Natural gas positions	$ 86	$ (5)	$ 79	$ 2	$ (16)	$ 5	$ (4)	$ (7)
Oil positions	77	(16)	46	15	(26)	16	(2)	(8)
Total	$ 163	$ (21)	$ 125	$ 17	$ (42)	$ 21	$ (6)	$ (15)

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The amount of gain (loss) recognized in "Commodity derivative income (expense)" in our consolidated statement of operations related to our derivative financial instruments was as follows:

	2013	2012	2011
	(In millions)		
Derivatives not designated as hedging instruments:			
Realized gain (loss) on natural gas positions	$66	$144	$249
Realized gain (loss) on oil positions	(6)	1	(47)
Realized gain (loss) on basis positions	—	(10)	(7)
Total realized gain[1]	60	135	195
Unrealized gain (loss) on natural gas positions	(81)	(124)	(48)
Unrealized gain (loss) on oil positions	(76)	99	47
Unrealized gain (loss) on basis positions	—	10	1
Total unrealized loss	(157)	(15)	—
Total	$(97)	$120	$195

(1) The total realized gain on commodity derivatives may differ from the cash receipts on derivative settlements as a result of the receipt or payment of premiums, or due to the recognition of premiums previously received associated with derivatives settled during the period.

6. Accounts Receivable:

Accounts receivable consisted of the following at December 31:

	2013	2012
	(In millions)	
Revenue	$294	$291
Joint interest	156	154
Other	25	8
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$474	$452

7. Accrued Liabilities:

Accrued liabilities consisted of the following at December 31:

	2013	2012
	(In millions)	
Revenue payable	$175	$95
Accrued capital costs	458	355
Accrued lease operating expenses	71	95
Employee incentive expense	51	50
Accrued interest on debt	72	43
Taxes payable	93	108
Other	58	55
Total accrued liabilities	$978	$801

8. Fair Value Measurements:

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The authoritative guidance requires disclosure of the framework for measuring fair value and requires that fair value measurements be classified and disclosed in one of the following categories:

Level 1:	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.
Level 2:	Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps and certain investments.
Level 3:	Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Level 3 instruments primarily include derivative instruments, such as commodity options (price collars and sold puts) and other financial investments.

- Our valuation models for derivative contracts are primarily industry-standard models (i.e., Black-Scholes) that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying commodities, as well as other relevant economic measures.

- Our valuation methodology for investments is a discounted cash flow model that considers various inputs including: (a) the coupon rate specified under the debt instruments, (b) the current credit ratings of the underlying issuers, (c) collateral characteristics and (d) risk-adjusted discount rates.

- Our valuation model for the Stockholder Value Appreciation Program (SVAP) is a Monte Carlo simulation that is based on a probability model and considers various inputs including: (a) the measurement date stock price, (b) time value and (c) historical and implied volatility. See Note 11, "Stock-Based Compensation," for a description of the SVAP.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Fair Value of Financial Instruments

The following table summarizes the valuation of our financial assets (liabilities) of our continuing operations by measurement levels:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In millions)			
As of December 31, 2012:				
Money market fund investments	$22	$—	$—	$22
Deferred compensation plan assets	6	—	—	6
Investments available-for-sale:				
Equity securities	7	—	—	7
Auction rate securities	—	—	36	36
Oil and gas derivative swap contracts	—	6	—	6
Oil and gas derivative option contracts	—	—	115	115
Stock-based compensation liability awards	(2)	—	—	(2)
Total	$33	$6	$151	$190
As of December 31, 2013:				
Money market fund investments	$2	$—	$—	$2
Deferred compensation plan assets	8	—	—	8
Investments available-for-sale:				
Equity securities	8	—	—	8
Auction rate securities	—	—	39	39
Oil and gas derivative swap contracts	—	(28)	—	(28)
Oil and gas derivative option contracts	—	—	(8)	(8)
Stock-based compensation liability awards	(11)	—	(5)	(16)
Total	$7	$(28)	$26	$5

The determination of the fair values above incorporates various factors, which include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), if any. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Level 3 Fair Value Measurements

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated periods:

	Investments	Derivatives	Stock-based Compensation	Total
	(In millions)			
Balance at January 1, 2011	$30	$48	$ —	$78
Total realized or unrealized gains (losses):				
Included in earnings	—	87	—	87
Included in other comprehensive income (loss)	4	—	—	4
Purchases, issuances and settlements:				
Settlements	(2)	(64)	—	(66)
Transfers in and out of Level 3	—	—	—	—
Balance at December 31, 2011	$32	$71	$ —	$103
Change in unrealized gains or losses included in earnings relating to Level 3 assets and liabilities still held at December 31, 2011	$—	$56	$ —	$56
Balance at January 1, 2012	$32	$71	$ —	$103
Total realized or unrealized gains (losses):				
Included in earnings	—	135	—	135
Included in other comprehensive income (loss)	4	—	—	4
Purchases, issuances and settlements:				
Settlements	—	(91)	—	(91)
Transfers in and out of Level 3	—	—	—	—
Balance at December 31, 2012	$36	$115	$ —	$151
Change in unrealized gains or losses included in earnings relating to Level 3 assets and liabilities still held at December 31, 2012	$—	$82	$ —	$82
Balance at January 1, 2013	$36	$115	$ —	$151
Total realized or unrealized gains (losses):				
Included in earnings	(6)	(66)	(18)	(90)
Included in other comprehensive income (loss)	10	—	—	10
Purchases, issuances and settlements:				
Settlements	(1)	(57)	13	(45)
Transfers in and out of Level 3	—	—	—	—
Balance at December 31, 2013	$39	$(8)	$ (5)	$26
Change in unrealized gains or losses included in earnings relating to Level 3 assets and liabilities still held at December 31, 2013	$(6)	$(10)	$ —	$(16)

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Investments. We utilize a discounted cash flow model in the determination of the valuation of our auction rate securities classified as Level 3. This model considers various inputs including (a) the coupon rate specified under the debt instrument, (b) the current credit rating of the underlying issuers, (c) collateral characteristics and

(d) risk-adjusted discount rates. The most significant unobservable factor in the determination of the investments fair value, however, is market liquidity for these instruments. A significant change in the liquidity of the market for auction rate securities would lead to a corresponding change in the fair value measurement of these investments.

As of December 31, 2013, we held $39 million of auction rate securities maturing beginning in 2033 that are classified as a Level 3 fair value measurement. This amount reflects an other than temporary decrease in the fair value of these investments since the time of purchase of $6 million ($4 million net of tax) recorded under the caption “Other income (expense) — Other,

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

net" on our consolidated statement of operations as a result of our decision to liquidate our auction rate investments. As of December 31, 2012, we held $36 million of auction rate securities, which reflected a decrease in the fair value of $9 million ($6 million net of tax) recorded under the caption "Accumulated other comprehensive income" on our consolidated balance sheet. The debt instruments underlying our auction rate securities are mostly investment grade (rated BBB or better) and are guaranteed by the United States government or backed by private loan collateral. Please see Note 1, "Organization and Summary of Significant Accounting Policies" for additional disclosure regarding our auction rate securities.

Derivatives. Our valuation models for Level 3 derivative option contracts are primarily industry-standard models that consider various factors, including certain significant unobservable inputs such as (a) quoted forward prices for commodities, (b) volatility factors and (c) counterparty credit risk. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the strike prices fixed by the hedge agreements, and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. Significant increases (decreases) in the quoted forward prices for commodities generally lead to corresponding decreases (increases) in the fair value measurement of our oil and gas derivative contracts. Significant changes in the volatility factors utilized in our option-pricing model can cause significant changes in the fair value measurement of our oil and gas derivative contracts.

The determination of the fair values of derivative instruments incorporates various factors that include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests). Historically, we have not experienced significant changes in the fair value of our derivative contracts resulting from changes in counterparty credit risk as the counterparties for all of our hedging transactions have an “investment grade” credit rating.

Stock-Based Compensation. The calculation of the fair value of the SVAP liability requires the use of a probability-based Monte Carlo simulation, which requires the use of unobservable inputs. The simulation predicts multiple scenarios of future stock return over the performance period, which are discounted to calculate the fair value. The fair value is recognized over a service period derived from the simulation. Future stock returns and discounting variables are sensitive to market volatility. Significant increases (decreases) in the volatility factors utilized in our option-pricing model can cause significant increases (decreases) in the fair value measurement of the SVAP liability.

Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Estimated Fair Value Asset (Liability) (In millions)	Quantitative Information about Level 3 Fair Value Measurements		
		Valuation Technique	Unobservable Input	Range
Oil option positions	$ (9)	Option model	NYMEX Oil price forward curve	$86.29 — $98.77
			Oil price volatility curves	14.33% — 23.22%
			Credit risk	0.01% — 0.89%
Natural gas option positions	$ 1	Option model	NYMEX Natural gas price forward curve	$4.01 — $4.42
			Natural gas price volatility curves	18.74% — 50.02%
			Credit risk	0.01% — 1.58%

SVAP	$ (5)	Monte Carlo	Historical volatility	37.4%
			Implied volatility	41.2%

The underlying inputs in the determination of the valuation of our auction rate securities are developed by a third party and, therefore, not included in the quantitative analysis above.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Fair Value of Debt

The estimated fair value of our notes, based on quoted prices in active markets (Level 1) as of December 31, was as follows:

	2013	2012
	(In millions)	
5¾% Senior Notes due 2022	$767	$836
5 % Senior Notes due 2024	1,025	1,074
7 % Senior Subordinated Notes due 2018	624	630
6 % Senior Subordinated Notes due 2020	755	749

Any amounts outstanding under our credit arrangements at December 31, 2013 and 2012 are stated at cost, which approximates fair value. Please see Note 9, "Debt."

9. Debt:

At December 31, our debt consisted of the following:

	2013	2012
	(In millions)	
Senior unsecured debt:		
Revolving credit facility — LIBOR based loans	$585	$—
Money market lines of credit[(1)]	64	—
Total credit arrangements	649	—
5¾% Senior Notes due 2022	750	750
5 % Senior Notes due 2024	1,000	1,000
Total senior unsecured debt	1,750	1,750
7 % Senior Subordinated Notes due 2018	600	600
6 % Senior Subordinated Notes due 2020	700	700
Discount on notes	(5)	(5)
Total long-term debt	$3,694	$3,045

(1) Because capacity under our credit facility was available to repay borrowings under our money market lines of credit as of the indicated dates, amounts outstanding under these obligations, if any, are classified as long-term.

Credit Arrangements

In April 2013, we entered into the second amendment to the credit facility, which allows the sale of the Company's international businesses pursuant to certain terms and conditions. In June 2013, we entered into the third amendment of our Credit Agreement. This amendment extended the maturity date of the revolving credit facility from June 2016 to June 2018 and increased the borrowing capacity from $1.25 billion to $1.4 billion. We incurred $4 million of deferred financing costs related to this amendment. As of December 31, 2013, the largest individual loan commitment by any lender was 14% of total commitments.

Loans under the credit facility bear interest, at our option, equal to (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank, N.A. or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points, plus a margin that is based on a grid of our debt rating (75 basis points per annum at December 31, 2013) or (b) the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (175 basis points per annum at December 31, 2013).

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Under our credit facility, we pay commitment fees on available but undrawn amounts based on a grid of our debt rating (30 basis points per annum at December 31, 2013). We incurred aggregate commitment fees under our current and previous credit facilities of approximately $3 million, $3 million and $2 million for each of the years ended December 31, 2013, 2012 and 2011, respectively, which are recorded in “Interest expense” on our consolidated statement of operations.

Our credit facility has restrictive financial covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0 and maintenance of a ratio of earnings before gain or loss on the disposition of assets, interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test writedowns and goodwill impairments) to interest expense of at least 3.0 to 1.0. At December 31, 2013, we were in compliance with all of our debt covenants.

As of December 31, 2013, we had $58 million letters of credit outstanding under our credit facility. Letters of credit are subject to a fronting fee of 20 basis points and annual fees based on a grid of our debt rating (175 basis points at December 31, 2013).

Subject to compliance with the restrictive covenants in our credit facility, at December 31, 2013, we also had a total of $96 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions.

The credit facility includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; inaccuracy of representations and warranties in any material respect; a change of control; or certain other material adverse changes in our business. Our senior notes and senior subordinated notes also contain standard events of default. If any of the foregoing defaults were to occur, our lenders under the credit facility could terminate future lending commitments, and our lenders under both the credit facility and our notes could declare the outstanding borrowings due and payable. In addition, our credit facility, senior notes, senior subordinated notes and substantially all of our hedging arrangements contain provisions that provide for cross defaults and acceleration of those debt and hedging instruments in certain situations.

Senior Notes

In June 2012, we issued $1 billion of 5 % Senior Notes due 2024 and received proceeds of $990 million (net of offering costs). These notes were issued at par to yield 5 %. We used a portion of the net proceeds to repay borrowings outstanding under our credit facility and money market lines of credit as well as redeem our 6 % Senior Subordinated Notes due 2016.

Interest on our senior notes is payable semi-annually. The notes are unsecured and unsubordinated obligations and rank equally with all of our other existing and future unsecured and unsubordinated obligations. We may redeem some or all of our senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing our senior notes contain covenants that may limit our ability to, among other things, incur debt secured by liens; enter into sale/leaseback transactions; and enter into merger or consolidation transactions.

The indentures also provide that if any of our subsidiaries guarantee any of our indebtedness at any time in the future, then we will cause our senior notes to be equally and ratably guaranteed by that subsidiary. At December 31, 2013, we were in compliance with all of our debt covenants.

Senior Subordinated Notes

Interest on our senior subordinated notes is payable semi-annually. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness.
We may redeem some or all of our 7 % Senior Subordinated Notes due 2018 at any time at a redemption price stated in the indenture governing the notes. We may redeem some or all of our 6 % Senior Subordinated Notes due 2020 at any time on or after February 1, 2015 at a redemption price stated in the indenture governing the notes. Prior to February 1, 2015, we may redeem some or all of these notes at a make-whole redemption price.

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The indenture governing our senior subordinated notes may limit our ability under certain circumstances to, among other things:

- incur additional debt;
- make restricted payments; and
- engage in mergers; consolidations; and sales and other dispositions of assets.

At December 31, 2013, we were in compliance with all of our debt covenants.

10. Income Taxes:

For the years ended December 31, the total provision (benefit) for income taxes for continuing operations consisted of the following:

	2013	2012	2011
	(In millions)		
Current taxes:			
U.S. federal	$(4)	$1	$17
U.S. state	—	1	—
Deferred taxes:			
U.S. federal	53	(479)	171
U.S. state	13	(34)	30
Total provision (benefit) for income taxes	$62	$(511)	$218

The provision for income taxes for each of the indicated years was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	2013	2012	2011
	(In millions)		
Amount computed using the statutory rate	$60	$(495)	$217
Increase (decrease) in taxes resulting from:			
State and local income taxes, net of federal effect	8	(18)	10
Valuation allowance, state net of federal	(2)	—	5
Other	(4)	2	(14)
Total provision (benefit) for income taxes	$62	$(511)	$218

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At December 31, the components of our deferred tax asset (liability) were as follows:

	2013	2012
	(In millions)	
Deferred tax asset:		
Net operating loss carryforwards	$335	$213
Alternative minimum tax credit	99	