SM Energy Co
Form 10-K
February 25, 2015

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, 2014
or
o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Commission file number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	80203 (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, $.01 par value	New York Stock Exchange

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 o

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yesþ Noo

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

Large accelerated filer þ	Accelerated filer o
	Smaller reporting company o

Non-accelerated filer o (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 o No þ

The aggregate market value of the 66,163,202 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the registrant's common stock on June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, of $84.10 per share, as reported on the New York Stock Exchange; was $5,564,325,288. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the registrant to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 18, 2015, the registrant had 67,463,060 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2015 annual meeting of stockholders to be filed within 120 days after December 31, 2014.

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PART I

When we use the terms “SM Energy,” “the Company,” “we,” “us,” or “our,” we are referring to SM Energy Company and its subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under Glossary of Oil and Gas Terms. Throughout this document we make statements that may be classified as “forward-looking.” Please refer to the Cautionary Information about Forward-Looking Statements section of this document for an explanation of these types of statements.

ITEMS 1. and 2. BUSINESS and PROPERTIES

General

We are an independent energy company engaged in the acquisition, exploration, development, and production of crude oil and condensate, natural gas, and natural gas liquids (also respectively referred to as “oil,” “gas,” and “NGLs,” respectively, throughout the document) in onshore North America. We were founded in 1908 and incorporated in Delaware in 1915. Our initial public offering of common stock was in December 1992. Our common stock trades on the New York Stock Exchange under the ticker symbol “SM.”

Our principal offices are located at 1775 Sherman Street, Suite 1200, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

Our strategic objective is to build our ownership and operatorship of North American oil, gas, and NGL producing assets that have high operating margins and significant opportunities for additional economic investment. We pursue opportunities through both acquisitions and exploration, and seek to maximize the value of our assets through industry leading technology application and outstanding operational execution. We are returns focused and maintain a simple, strong balance sheet through a conservative approach to leverage.

Significant Developments in 2014

- Resource Play Delineation and Development Results in Record Production and Record Year-End Proved Reserve Estimates. Our estimated proved reserves increased 28 percent to 547.7 MMBOE at December 31, 2014, from 428.7 MMBOE at December 31, 2013. We added 143.9 MMBOE through drilling activities during the year, led by our efforts in our Eagle Ford shale play in south Texas and our Bakken/Three Forks play in North Dakota. Our proved reserve life increased to 9.9 years in 2014 compared to 8.9 years in 2013. We also achieved record levels of production in 2014. Our average daily production was composed of 45.6 MBbl of oil, 419.0 MMcf of gas, and 35.6 MBbl of NGLs for an average equivalent production rate of 151.1 MBOE per day, which was an increase of 14 percent from an average of 132.4 MBOE per day in 2013. Costs incurred for drilling and exploration activities, excluding acquisitions, increased 36 percent to $2.1 billion in 2014 when compared to 2013. Please refer to Core Operational Areas below for additional discussion concerning our 2014 estimated proved reserves, production, and capital investment.
- Acquisition Activity. During 2014, we acquired a total of 21.9 MMBOE of proved reserves through multiple transactions for consideration of approximately $544.6 million in cash plus approximately 7,000 net acres of non-core assets in our Rocky Mountain region. Through these acquisitions, we added approximately 74,000 net acres in our Gooseneck area in Divide County, North Dakota and approximately 38,000 net acres in our Powder River Basin program in Wyoming.
- Volatility and Decline in Commodity Prices. Our financial condition and results of operations are significantly affected by the prices we receive for oil, gas, and NGLs, which can fluctuate dramatically.

Oil prices drastically declined in late 2014. The daily NYMEX spot price ranged from a high of $107.62 per Bbl in July to a low of $53.27 per Bbl in December. Oil prices declined further subsequent to year end 2014, dropping to a low of $44.45 per Bbl in January 2015. The average NYMEX price decreased to $93.03 per Bbl in 2014 compared to $97.99 per Bbl in 2013.
Natural gas prices have been under downward pressure due to high levels of supply in recent years and were volatile during 2014. The daily NYMEX spot price improved early in 2014 with a high of $7.92 per MMBtu in March and then dropped significantly to a low of $2.75 per MMBtu in December. Gas prices declined further subsequent to year end 2014, dropping to a low of $2.55 per MMBtu in February 2015. The average NYMEX price increased in 2014 to $4.35 per MMBtu compared to $3.73 per MMBtu in 2013.
NGL prices decreased in 2014 in line with the steep decline in oil prices. The monthly OPIS NGL price reached a high of $48.43 per Bbl in February and a low of $22.44 per Bbl in December. NGL prices declined further subsequent to year end 2014, dropping to a low of $20.03 per Bbl in January 2015. The average OPIS price decreased in 2014 to $38.93 per Bbl compared to $40.44 per Bbl in 2013.

- Impairments. We recorded impairment of proved properties expense of $84.5 million and abandonment and impairment of unproved properties expense of $75.6 million for the year ended December 31, 2014. Impairments recorded in 2014 were a result of the significant decline in commodity prices in late 2014 and recognition of the outcomes of exploration and delineation wells in certain prospects in our South Texas & Gulf Coast and Permian regions.

Outlook for 2015

We view 2015 as a year of transition as the broader oil and gas industry adjusts to lower oil prices. Exploration and production companies are reducing drilling and completion activity, which we expect to result in service companies lowering the price of their services. Our plan for 2015 is to scale down activity over the course of the year while preserving the value of our assets and protecting the strength of our balance sheet. Our goal is to be well positioned entering 2016 in what we expect will be a stronger commodity price and lower service cost environment, while having the strength and flexibility to adapt should industry conditions worsen.

Our capital program for 2015 will be approximately $1.2 billion, of which approximately $1.0 billion will be invested in drilling and completion activities. We expect to focus 85 percent of our drilling and completion capital on our core development programs in the Eagle Ford shale and the Bakken/Three Forks formations. The remaining capital is being allocated to the construction of facilities, leasehold acquisitions, exploration overhead, and geological and geophysical costs. Please refer to Outlook for 2015 under Part II, Item 7 of this report for additional discussion concerning our capital plans for 2015.

Core Operational Areas

Our operations are concentrated in four onshore operating areas in the United States. The following table summarizes estimated proved reserves, PV-10, production, and costs incurred in oil and gas activities for the year ended December 31, 2014, for our core operating areas:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total (1)
Proved Reserves					
Oil (MMBbl)	64.5	91.5	13.5	0.2	169.7
Gas (Bcf)	1,193.3	89.6	38.9	144.8	1,466.5
NGLs (MMBbl)	131.2	2.0	—	0.4	133.5
MMBOE (1)	394.6	108.4	20.0	24.7	547.7
Relative percentage	72 %	20 %	4 %	4 %	100 %
Proved Developed %	48 %	56 %	76 %	83 %	52 %
PV-10 (in millions) (2)					
Proved Developed	$2,942.8	$1,651.5	$440.8	$217.9	$5,253.0
Proved Undeveloped	1,593.0	699.0	55.5	16.4	2,363.9
Total Proved	$4,535.8	$2,350.5	$496.3	$234.3	$7,616.9
Relative percentage	60 %	31 %	6 %	3 %	100 %
Production					
Oil (MMBbl)	7.1	7.4	2.0	0.1	16.7
Gas (Bcf)	121.6	7.0	4.5	19.8	152.9
NGLs (MMBbl)	12.8	0.1	—	0.1	13.0
MMBOE (1)	40.2	8.7	2.8	3.5	55.1
Avg. Daily Equivalents (MBOE/d)	110.1	23.9	7.6	9.5	151.1
Relative percentage	73 %	16 %	5 %	6 %	100 %
Costs Incurred (in millions)(3)	$1,187.8	$1,241.8	$195.4	$58.9	$2,711.7

(1) Totals may not sum or recalculate due to rounding.

(2) The standardized measure PV-10 calculation is presented in the Supplemental Oil and Gas Information section in Part II, Item 8 of this report. A reconciliation between PV-10 and the after tax amount is shown in the Reserves section below.

(3) Amounts do not sum to total costs incurred due to certain costs relating to our new venture projects being excluded from the regional table above.

South Texas & Gulf Coast Region. Operations in our South Texas & Gulf Coast region are managed from our office in Houston, Texas. Within this region, we have both operated and non-operated Eagle Ford shale programs on approximately 180,000 net acres. Our operated program accounts for approximately 75 percent of our total Eagle Ford acreage and production. Our acreage position covers a significant portion of the western Eagle Ford shale play, including acreage in the oil/condensate, NGL-rich gas, and dry gas windows of the play.

In addition, we continued to evaluate an emerging new venture play in east Texas in 2014. We have approximately 215,000 net acres that provide opportunities in the Austin Chalk, Woodbine, and Eagle Ford shale intervals. During 2014, we constructed a gathering system to allow for longer-term production tests on our wells.

We deployed a significant amount of capital in our South Texas & Gulf Coast region in 2014 in our operated and outside-operated Eagle Ford shale programs. Costs incurred increased to $1.2 billion in 2014 from $849.4 million in 2013. Estimated proved reserves at year-end 2014 increased 27 percent from 311.2 MMBOE at year-end 2013. We added approximately 105.8 MMBOE of estimated proved reserves through drilling activities. During 2012, 2013, and early 2014, we were carried for substantially all of our drilling and completion costs in our outside-operated Eagle Ford program pursuant to our Acquisition and Development Agreement with Mitsui E&P Texas LP ("Mitsui"), an indirect subsidiary of Mitsui & Co., Ltd. (the "Acquisition and Development Agreement"). The remainder of our carry was expended during the first and second quarters of 2014, at which point we began accruing and funding our share of previously carried drilling and completion costs. Please refer to Note 12 - Acquisition and Development Agreement in Part II, Item 8 for additional discussion. Production in 2014 increased 30 percent from the 30.9 MMBOE produced in 2013.

Rocky Mountain Region. Operations in our Rocky Mountain region are managed from our office in Billings, Montana. Our 2014 activity in this region focused on the development and growth through acquisition of assets targeting the Bakken/Three Forks formations, primarily in Williams, McKenzie, and Divide Counties of North Dakota, and on the expansion and delineation of our Powder River Basin program in Wyoming. In the Williston Basin, we have approximately 245,000 net acres, of which approximately 160,000 net acres are being actively developed in the Bakken and Three Forks formations. In the Powder River Basin, we have approximately 175,000 net acres, a large portion of which are prospective for the Frontier and Shannon intervals.

Costs incurred in our Rocky Mountain region increased from $474.7 million in 2013 to $1.2 billion in 2014, largely as a result of our Williston Basin and Powder River Basin proved and unproved property acquisitions totaling $561.6 million in 2014. This amount includes the fair value of properties acquired in an asset exchange and the estimated asset retirement obligations associated with the acquired producing properties. Estimated proved reserves for the region at the end of 2014 increased 43 percent from 76.0 MMBOE at year-end 2013. During the year, we added approximately 25.3 MMBOE of proved reserves in this region through drilling activities and approximately 21.9 MMBOE through acquisitions. Production for 2014 increased 18 percent from 7.4 MMBOE produced in 2013.

Permian Region. Operations in our Permian region are managed from our office in Midland, Texas. Our Permian region covers western Texas and southeastern New Mexico. Our 2014 activity focused on the testing of shale potential and development of our assets in the Midland Basin. As of December 31, 2014, we had approximately 113,000 net acres in our Permian region.

Costs incurred in our Permian region decreased to $195.4 million in 2014 compared to $275.7 million in 2013. Estimated proved reserves increased 22 percent from 2013 year-end proved reserves of 16.3 MMBOE. Production increased 16 percent from 2.4 MMBOE produced in 2013.

Mid-Continent Region. Our Mid-Continent region is managed from our office in Tulsa, Oklahoma, and consists of our Haynesville and Woodford Shale assets.

Costs incurred in our Mid-Continent region decreased to $58.9 million in 2014 compared to $91.9 million incurred in 2013. Estimated proved reserves decreased two percent from 2013 year-end proved reserves of 25.2 MMBOE. Production decreased 55 percent from 7.7 MMBOE produced in 2013, primarily as a result of the divestiture of our Anadarko Basin assets in December 2013.

Subsequent to December 31, 2014, we announced plans to close our regional office in Tulsa, Oklahoma and market our remaining assets located in the Arkoma Basin of Oklahoma and Arklatex area of east Texas and northern Louisiana.

Reserves

The table below presents summary information with respect to the estimates of our proved reserves for each of the years in the three-year period ended December 31, 2014. We engaged Ryder Scott Company, L.P. ("Ryder Scott") to audit at least 80 percent of our total calculated proved reserve PV-10 for each year presented. The prices used in the calculation of proved reserve estimates reflect the 12 month average of the first-day-of-the-month prices in accordance with Securities and Exchange Commission ("SEC") rules, and were $94.99 per Bbl for oil, $4.35 per MMBtu for natural gas, and $39.91 per Bbl for NGLs for the year ended December 31, 2014. We then adjust these prices to reflect appropriate basis, quality, and location differentials over the period in estimating our proved reserves.

Reserve estimates are inherently imprecise and estimates for new discoveries and undeveloped locations are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. PV-10 shown in the following table is not intended to represent the current market value of our estimated proved reserves. The actual quantities and present value of our estimated proved reserves may be more or less than we have estimated. No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the SEC, since the beginning of the last fiscal year.

The following table should be read along with the section entitled Risk Factors – Risks Related to Our Business below.

Our ability to replace our production is critical to us. Please refer to the reserve replacement terms in the Glossary of Oil and Gas Terms section of this report for information describing how our reserve replacement metrics are calculated. Our reserve replacement percentages are calculated using information from the Oil and Gas Reserve Quantities section of Supplemental Oil and Gas Information located in Part II, Item 8 of this report. We believe the concept of reserve replacement, as well as reserve metrics presented in this report, are widely understood by those who make investment decisions related to the oil and gas exploration and production business.

The following table summarizes estimated proved reserves, PV-10, standardized measure of discounted future cash flows, and reserve replacement as of December 31, 2014, 2013, and 2012:

	As of December 31,					
	2014		2013		2012	
Reserve data:						
Proved developed						
Oil (MMBbl)	89.3		70.2		58.8	
Gas (Bcf)	784.6		569.2		483.2	
NGLs (MMBbl)	66.7		43.8		27.2	
MMBOE (1)	286.8		208.9		166.5	
Proved undeveloped						
Oil (MMBbl)	80.4		56.3		33.5	
Gas (Bcf)	682.0		620.1		350.2	
NGLs (MMBbl)	66.8		60.2		35.1	
MMBOE (1)	260.9		219.9		126.9	
Total Proved (1)						
Oil (MMBbl) (1)	169.7		126.6		92.2	
Gas (Bcf) (1)	1,466.5		1,189.3		833.4	
NGLs (MMBbl) (1)	133.5		103.9		62.3	
MMBOE (1)	547.7		428.7		293.4	
Proved developed reserves %	52	%	49	%	57	%
Proved undeveloped reserves %	48	%	51	%	43	%
Reserve data (in millions):						
Proved developed PV-10	$5,253.0		$3,898.6		$2,982.6	
Proved undeveloped PV-10	2,363.9		1,629.9		866.5	
Total proved PV-10	$7,616.9		$5,528.5		$3,849.1	
Standardized measure of discounted future cash flows	$5,698.8		$4,009.4		$3,021.0	
Reserve replacement – drilling, excluding revisions	261	%	405	%	411	%
All in – including sales of reserves	316	%	380	%	329	%
All in – excluding sales of reserves	320	%	418	%	337	%
Reserve life (years)	9.9		8.9		8.0	

(1) Totals may not sum or recalculate due to rounding.

The following table reconciles the standardized measure of discounted future net cash flows (GAAP) to the pre-tax PV-10 (Non-GAAP) of total proved reserves. Please see the definitions of standardized measure of discounted future net cash flows and PV-10 in the Glossary of Oil and Gas Terms section of this report below.

	As of December 31, 2014 (in millions)	2013	2012
Standardized measure of discounted future net cash flows	$5,698.8	$4,009.4	$3,021.0
Add: 10 percent annual discount, net of income taxes	3,407.2	2,500.6	1,742.1
Add: future undiscounted income taxes	3,511.4	2,722.2	1,609.4
Undiscounted future net cash flows	12,617.4	9,232.2	6,372.5
Less: 10 percent annual discount without tax effect	(5,000.5)	(3,703.7)	(2,523.4)
PV-10	$7,616.9	$5,528.5	$3,849.1

Proved Undeveloped Reserves

Proved undeveloped reserves include those 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. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time period. As of December 31, 2014, we had one undrilled proved undeveloped location on our operated Eagle Ford asset that had been on our books in excess of five years. Drilling has been initiated on that location as of the date of this report.

For locations that are more than one location removed from developed producing locations, we utilized reliable geologic and engineering technology to add approximately 61.9 MMBOE of proved undeveloped reserves in the more developed portions of our Eagle Ford shale position and 5.6 MMBOE of proved undeveloped reserves in the more developed portions of our Bakken/Three Forks shale position. We incorporated public and proprietary data from multiple sources to establish geologic continuity of each formation and their producing properties. This included seismic data and interpretations (3-D and micro seismic), open hole log information (both vertically and horizontally collected), and petrophysical analysis of the log data, mud logs, gas sample analysis, measurements of total organic content, thermal maturity, test production, fluid properties, and core data as well as significant statistical performance data yielding predictable and repeatable reserve estimates within certain analogous areas. These locations were limited to only those areas where both established geologic consistency and sufficient statistical performance data could be demonstrated to provide reasonably certain results. In all other areas, we restricted proved undeveloped locations to immediate offsets to producing wells.

As of December 31, 2014, we had 260.9 MMBOE of proved undeveloped reserves, which is an increase of 41.0 MMBOE, or 19 percent, from 219.9 MMBOE at December 31, 2013. The following table provides a reconciliation of our proved undeveloped reserves for the year ended December 31, 2014:

	Total (MMBOE)
Total proved undeveloped reserves:	
Beginning of year	219.9
Revisions of previous estimates [1]	6.6
Additions from discoveries, extensions, and infill [2]	113.0
Sales of reserves	—
Purchases of minerals in place	13.9
Removed for five-year rule	(4.3)
Conversions to proved developed [3]	(88.2)
End of year	260.9

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(1) Revisions of previous estimates primarily relate to a positive performance revision of 6.1 MMBOE on our operated Eagle Ford assets due to improved performance and lower operating expenses.

(2) We added 85.0 MMBOE of infill proved undeveloped reserves primarily in our assets in the Bakken/Three Forks and Eagle Ford shale plays, as well as an additional 28.0 MMBOE of proved undeveloped reserves through extensions and discoveries, primarily in our Eagle Ford shale play.

(3) Conversions of proved undeveloped reserves to proved developed reserves were primarily in our Eagle Ford shale and Bakken/Three Forks plays. During 2014, we incurred a total of $908.6 million on projects associated with reserves booked as proved undeveloped reserves at the end of 2013. Please refer to Note 12 - Acquisition and Development Agreement in Part II, Item 8 of this report for discussion of the carry of certain drilling and completion costs in our outside-operated Eagle Ford program during the first and second quarters of 2014.

As of December 31, 2014, estimated future development costs relating to our proved undeveloped reserves are approximately $746 million, $921 million, and $840 million in 2015, 2016, and 2017, respectively.

Internal Controls Over Proved Reserves Estimates

Our internal controls over the recording of proved reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with the SEC's regulations. Our process for managing and monitoring our proved reserves is delegated to our corporate reserves group, which is managed by our Senior Manager of Reserves, subject to the oversight of our management and the Audit Committee of our Board of Directors, as discussed below. Our Senior Manager of Reserves has over 15 years of experience in the energy industry, and holds a Bachelor of Science degree in Chemical Engineering with a Petroleum Certificate from the University of Alabama. She is also a member of the Society of Petroleum Engineers. Technical, geological, and engineering reviews of our assets are performed throughout the year by our regional staff. This data, in conjunction with economic data and our ownership information, is used in making a determination of estimated proved reserve quantities. Our regional engineering technical staff do not report directly to our Senior Manager of Reserves; they report to either their respective regional technical managers or directly to the regional manager. This design is intended to promote objective and independent analysis within our regions in the proved reserves estimation process.

Third-party Reserves Audit

Ryder Scott performed an independent audit using its own engineering assumptions, but with economic and ownership data we provided. Ryder Scott audits a minimum of 80 percent of our total calculated proved reserve PV-10. In the aggregate, the proved reserve amounts of our audited properties determined by Ryder Scott are required to be within 10 percent of our proved reserve amounts for the total company, as well as for each respective region. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services throughout the world for over 70 years. The technical person at Ryder Scott primarily responsible for overseeing our reserves audit is an Advising Senior Vice President who received a Bachelor of Science degree in Chemical Engineering from Purdue University in 1979 and a Master of Science Degree in Chemical Engineering from the University of California, Berkeley, in 1981. He is a licensed Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers, and the Society of Petroleum Evaluation Engineers. The Ryder Scott 2014 report concerning our reserves is included as Exhibit 99.1.

In addition to a third party audit, our reserves are reviewed by our management with the Audit Committee of our Board of Directors. Management, which includes our President and Chief Executive Officer, Executive Vice President and Chief Financial Officer, and Executive Vice President - Operations, is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The Audit Committee reviews a summary of the final reserves estimate in conjunction with Ryder Scott's results and also meets with Ryder Scott representatives from time to time to discuss processes and findings.

Production

The following table summarizes the volumes and realized prices of oil, gas, and NGLs produced and sold from properties in which we held an interest during the periods indicated. Realized prices presented below exclude the effects of derivative contract settlements. Also presented is a summary of related production costs per BOE.

	For the Years Ended December 31,		
	2014	2013	2012
Net production			
Oil (MMBbl)	16.7	13.9	10.4
Gas (Bcf)	152.9	149.3	120.0
NGLs (MMBbl)	13.0	9.5	6.1
MMBOE (2)	55.1	48.3	36.5
Eagle Ford net production(1)			
Oil (MMBbl)	6.9	5.1	3.1
Gas (Bcf)	120.6	97.1	58.1
NGLs (MMBbl)	12.7	9.2	5.7
MMBOE(2)	39.7	30.5	18.5
Realized price			
Oil (per Bbl)	$80.97	$91.19	$85.45
Gas (per Mcf)	$4.58	$3.93	$2.98
NGLs (per Bbl)	$33.34	$35.95	$37.61
Per BOE	$45.01	$45.50	$40.39
Production costs per BOE			
Lease operating expense, excluding ad valorem taxes	$4.28	$4.49	$4.54
Ad valorem taxes	$0.46	$0.33	$0.39
Transportation costs	$6.11	$5.34	$3.81
Production taxes	$2.13	$2.19	$2.00

(1) In each of the years 2014, 2013, and 2012, total estimated proved reserves attributed to our Eagle Ford shale properties exceeded 15 percent of our total proved reserves expressed on an equivalent basis.

(2) Amounts may not recalculate due to rounding.

Productive Wells

As of December 31, 2014, we had working interests in 1,500 gross (869 net) productive oil wells and 2,648 gross (931 net) productive gas wells. Productive wells are either wells producing in commercial quantities or wells mechanically capable of commercial production, but are temporarily shut-in. Multiple completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil produced when it first commenced production; such designation may not be indicative of current production.

Drilling and Completion Activity

All of our drilling and completion activities are conducted using independent contractors. We do not own any drilling or completion equipment. The following table summarizes the number of operated and outside-operated wells drilled and completed or recompleted on our properties in 2014, 2013, and 2012, excluding non-consented projects, active injector wells, salt water disposal wells, and any wells in which we own only a royalty interest:

	For the Years Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	133	66.1	154	75.4	127	47.2
Gas	476	165.5	443	162.5	337	124.5
Non-productive	8	5.3	10	8.5	10	6.3
	617	236.9	607	246.4	474	178.0
Exploratory wells:						
Oil	5	3.0	6	5.1	9	6.9
Gas	7	4.8	4	2.4	8	6.8
Non-productive	4	3.3	1	0.3	8	6.8
	16	11.1	11	7.8	25	20.5
Total	633	248.0	618	254.2	499	198.5

A productive well is an exploratory, development, or extension well that is producing or capable of commercial production of oil, gas, and/or NGLs. A non-productive well, frequently referred to within the industry as a dry hole, is an exploratory, development, or extension well that proves to be incapable of producing oil, gas, and/or NGLs in commercial quantities.

As defined by the SEC, an exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. A development well is a well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of equipment for production of oil, gas, and/or NGLs, or in the case of a dry well, the reporting to the appropriate authority that the well has been plugged and abandoned.

In addition to the wells drilled and completed in 2014 (included in the table above), as of February 18, 2015, we were participating in the drilling of 22 gross wells. We operate 15 of these wells on a gross basis (14 on a net basis) and other companies operate the remaining 7 gross wells (1 on a net basis). With respect to completion activity, at such date, there were 326 gross wells in which we have an interest that were being completed. We operate 87 of these completion activities on a gross basis (78 on a net basis), and were participating in 239 gross (40 on a net basis) outside-operated completion activities.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leasehold, fee properties, and mineral servitudes held by us as of December 31, 2014. Undeveloped acreage includes leasehold interests containing proved undeveloped reserves.

	Developed Acres [1]		Undeveloped Acres [2]		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	51,079	19,319	33,766	30,858	84,845	50,177
Montana	50,479	32,654	268,334	184,941	318,813	217,595
North Dakota	313,809	159,199	159,782	68,675	473,591	227,874
Oklahoma	46,121	26,330	40,411	19,694	86,532	46,024
Texas	304,710	166,078	618,047	421,244	922,757	587,322
Wyoming	59,366	36,499	383,906	303,346	443,272	339,845
Other [3]	22,637	17,049	40,707	34,981	63,344	52,030
Total [4][5]	848,201	457,128	1,544,953	1,063,739	2,393,154	1,520,867

(1) Developed acreage is acreage assigned to producing wells for the state approved spacing unit for the producing formation. Our developed acreage that includes multiple formations with different well spacing requirements may be considered undeveloped for certain formations, but has been included only as developed acreage in the presentation above.

(2) Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and/or NGLs regardless of whether such acreage contains estimated net proved reserves.

(3) Includes interests in Arkansas, Colorado, Kansas, Mississippi, Nebraska, New Mexico, Pennsylvania, Utah, and insignificant other fee and mineral servitude properties.

(4) As of the filing date of this report, we had 165,995, 185,174, and 81,249 net acres scheduled to expire by December 31, 2015, 2016, and 2017, respectively, if production is not established or we take no other action to extend the terms of the applicable lease or leases.

(5) Subsequent to December 31, 2014, we announced plans to exit the Mid-Continent region and sell approximately 113,000 net acres in the Arkoma Basin of Oklahoma and Arklatex area of east Texas and northern Louisiana in 2015.

Delivery Commitments

As of December 31, 2014, we had gathering, processing, and transportation through-put commitments with various parties that require us to deliver fixed, determinable quantities of production over specified time frames. We have an aggregate minimum commitment to deliver 1,411 Bcf of natural gas and 48 MMBbl of oil. These contracts expire at various dates through 2028. We are required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment for natural gas is projected, we have rights under certain contracts to arrange for third party gas to be delivered, and such volume will count toward our minimum volume commitment. Our current production is insufficient to offset these aggregate contractual liabilities, but we expect to fulfill the delivery commitments with production from the future development of our proved undeveloped reserves and from the future development of resources not yet characterized as proved reserves or through arranging for the delivery of third party gas. Therefore, we do not expect any material shortfalls.

Major Customers

We do not believe the loss of any single purchaser of our crude oil, natural gas, and NGLs would materially impact our operating results, as these are products with well-established markets and numerous purchasers are present in our operating regions. During 2014, we had one major customer that accounted for approximately 19 percent of our total production revenue, which is discussed in the next paragraph. In 2014, we also sold to four entities that are under common ownership. In aggregate, these four entities accounted for approximately 14 percent of our total production revenue in 2014; however, none of these entities individually accounted for greater than 10 percent of our production revenues. During 2013, we had three major customers that accounted for approximately 26 percent, 16 percent, and 12 percent, respectively, of our total production revenue. During 2012, we had two major customers that accounted for approximately 21 percent and 13 percent, respectively, of our total production revenue.

During the third quarter of 2013, we entered into various marketing agreements with a joint venture partner, whereby we are subject to certain gathering, transportation, and processing through-put commitments for up to 10 years pursuant to each contract. While our joint venture partner is the first purchaser under these contracts, accounting for 19 percent of our total production revenue in 2014, we also share with it the risk of non-performance by its counterparty purchasers and have included this joint venture partner as a major customer in the discussion above. Several of the joint venture partner’s counterparty purchasers under these contracts are also direct purchasers of our production.

Employees and Office Space

As of February 18, 2015, we had 896 full-time employees. None of our employees are subject to a collective bargaining agreement, and we consider our relations with our employees to be good.

The following table summarizes the approximate square footage of office space leased by us, as of December 31, 2014, including our corporate headquarters and regional offices:

Region	Approximate Square Footage Leased
Corporate	101,000
South Texas & Gulf Coast	64,000
Rocky Mountain	50,000
Permian	54,000
Mid-Continent	54,000
Total Leased Office Space	323,000

In addition to the leased office space in the table above, we own a total of 44,000 square feet of office space across all four of our operating regions.

Subsequent to year end 2014, we announced plans to close our Tulsa, Oklahoma regional office in 2015.

Title to Properties

Substantially all of our interests are held pursuant to oil and gas leases from third parties. A title opinion is usually obtained prior to the commencement of initial drilling operations. We have obtained title opinions or have conducted other title review on substantially all of our producing properties and believe we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. Most of our producing properties are subject to mortgages securing indebtedness under our credit facility, royalty and overriding royalty interests, liens for current taxes, and other burdens that we believe do not materially interfere with the use of, or affect the value of, such properties. We typically perform only minimal title investigation before acquiring undeveloped leasehold acreage.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during winter months and decrease during summer months. To lessen the impact of seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can place increased demand on storage volumes. Demand for oil and heating oil is also generally higher in the winter and the summer driving season, although oil prices are impacted more significantly by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. Recently, the impact of seasonality on oil has been somewhat muted by overall supply and demand economics attributable to worldwide production capacity in excess of existing worldwide demand for oil. Certain of our drilling, completion, and other operations are also subject to seasonal limitations. Seasonal weather conditions, government regulations and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate. See Risk Factors - Risks Related to Our Business below for additional discussion.

Competition

The oil and gas industry is intensely competitive, particularly with respect to acquiring prospective oil and natural gas properties. We believe our acreage position provides a foundation for development activities that we expect to fuel our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, as well as our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete in our core operating areas. However, we face intense competition from a substantial number of major and independent oil and gas companies, which in some cases have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have gathering, processing or refining operations, market refined products, own drilling rigs or other equipment, or generate electricity.

We also compete with other oil and gas companies in securing drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells, as well as for the gathering, transporting and processing of crude oil, natural gas and NGLs. Consequently, we may face shortages, delays or increased costs in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may be affected by future energy, climate-related, financial, and/or other policies, legislation, and regulations.

In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other professionals. Throughout the oil and gas industry, the need to attract and retain talented people has grown at a time when the availability of individuals with these skills is becoming more limited due to the evolving demographics of our industry. We are not insulated from the competition for quality people, and we must compete effectively in order to be successful.

Government Regulations

Our business is extensively controlled by numerous federal, state, and local laws and governmental regulations. These laws and regulations may be changed from time to time in response to economic or political conditions, or other developments, and our regulatory burden may increase in the future. Laws and regulations have the potential of increasing our cost of doing business and consequently could affect our profitability. However, we do not believe that

we are affected to a materially greater or lesser extent than others in our industry.
Energy Regulations. Many of the states in which we conduct our operations have adopted laws and regulations governing the exploration for and production of oil, gas, and NGLs, including laws and regulations requiring permits for the drilling of wells, impose bonding requirements in order to drill or operate wells, and govern the timing of drilling and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to various state conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of oil and gas properties. In addition, state conservation laws sometimes establish maximum rates of production from oil and gas wells, generally limit or prohibit the venting or flaring of gas, and

may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management (“BLM”). These leases contain relatively standardized terms and require compliance with detailed regulations and orders that are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and must comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM may suspend or terminate our operations on federal leases. In May 2010, the BLM adopted changes to its oil and gas leasing program requiring, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, increased public engagement in the development of master leasing and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process. These changes have increased the amount of time and regulatory costs necessary to obtain oil and gas leases administered by the BLM.

Our sales of natural gas are affected by the availability, terms, and cost of gas pipeline transportation. The Federal Energy Regulatory Commission (“FERC”) has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce. FERC’s current regulatory framework generally provides for a competitive and open access market for sales and transportation of natural gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect the sales prices we receive for natural gas production.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state, tribal and local laws and regulations governing protection of the environment and worker health and safety as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, including areas containing certain wildlife or threatened and endangered plant and animal species; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes may result in more stringent permitting, waste handling, disposal and cleanup requirements for the oil and natural gas industry and could have a significant impact on our operating costs.
The following is a summary of some of the existing laws, rules and regulations to which our business is subject.
Waste handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (the "EPA"), individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced water, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.
Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, pay fines, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States and states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, U.S. Army Corps of Engineers or analogous state agencies. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990 ("OPA") addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in governmental penalties and civil liability.

Air emissions. The federal Clean Air Act ("CAA"), and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. Legislative and regulatory initiatives related to climate change could have an adverse effect on our operations and the demand for oil and gas. See Risk Factors - Risks Related to Our Business - Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil, natural gas and NGLs. In addition to the effects of regulation, the meteorological effects of global climate change could pose additional risks to our operations, including physical damage risks associated with more frequent, more intensive storms and flooding, and could adversely affect the demand for our products.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts on protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on these species. It is also possible that a federal or state agency could order a complete halt to activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling, completion and production activities could impair our ability to timely complete well drilling and development and could adversely affect our future production from those areas.

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

OSHA and other laws and regulation. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in most of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's (the "SDWA") Underground Injection Control Program. The federal SDWA protects the quality of the nation's public drinking water through the adoption of drinking water standards and controlling the injection of waste fluids, including saltwater disposal fluids, into below-ground formations that may adversely affect drinking water sources.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas activities using hydraulic fracturing techniques, which could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs, and delays, all of which could adversely affect our financial position, results of operations and cash flows. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, which could result in additional permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

We believe it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot give any assurance that we will not be adversely affected in the future.

Environmental, Health and Safety Initiatives. We are committed to conducting our business in a manner that protects the environment and the health and safety of our employees, contractors and the public. We set annual goals for our environmental, health and safety program focused on reducing the number of safety related incidents that occur and the number and impact of spills of produced fluids. We also periodically conduct regulatory compliance audits of our operations to ensure our compliance with all regulations and provide appropriate training for our employees. Reducing air emissions as a result of leaks, venting or flaring of natural gas during operations has become a major focus area for regulatory efforts and for our compliance efforts. While flaring is sometimes necessary, releases of natural gas to the environment and flaring is an economic waste and reducing these volumes is a priority for us. To avoid flaring where possible, we restrict testing periods and make every effort to ensure that our production is connected to gas pipeline infrastructure as quickly as possible after well completions. During 2013 and 2014, we also cooperated with other producers in North Dakota in the ongoing development of recommendations to reduce the amount of flaring that is occurring there as a result of area wide infrastructure limitations that are beyond our control. Another focus for our environmental effort has been reduction of water use through recycling of flowback water in south Texas for use as frac fluid. We have incurred in the past, and expect to incur in the future, capital costs related to environmental compliance. Such expenditures are included within our overall capital budget and are not separately itemized.

Cautionary Information about Forward-Looking Statements

This Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project, similar expressions are intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-K, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- future oil, gas, and NGL production estimates;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section in Item 7 of this Form 10-K.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Some of these risks are described in the Risk Factors section of this Form 10-K, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital required to develop and/or replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on outside operated properties;
- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we have an interest may be defective;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with acquisitions, divestitures, joint ventures, farm-downs, farm-outs and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts may result in financial losses or may limit the prices we receive for oil, gas, and NGL sales;
- the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver necessary quantities of natural gas or crude oil to contractual counterparties;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that lower oil, gas, or NGL prices could have on the amount we are able to borrow under our credit facility;

- the possibility our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- the possibility that covenants in our debt agreements may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions or lead to the accelerated payment of our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of seasonal weather conditions and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental and other applicable rules;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;
- the possibility we may face unforeseen difficulties or expenses related to our implementation of a new enterprise resource planning software system ("ERP"); and
- litigation, environmental matters, the potential impact of legislation and government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing date of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

Available Information

Our internet website address is www.sm-energy.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. We also make available through our website's corporate governance section our Corporate Governance Guidelines, Code of Business Conduct and Conflict of Interest Policy, Financial Code of Ethics, and the Charters of the Audit, Compensation, Executive, and Nominating and Corporate Governance Committees of our Board of Directors. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

Glossary of Oil and Gas Terms
The oil and gas terms defined in this section are used throughout this report. The definitions of the terms developed reserves, exploratory well, field, proved reserves, and undeveloped reserves have been abbreviated from the respective definitions under SEC Rule 4-10(a) of Regulation S-X, as amended effective for fiscal years ending after December 31, 2009. The entire definitions of those terms under Rule 4-10(a) of Regulation S-X can be located through the SEC's website at www.sec.gov.
Ad valorem tax. A tax based on the value of real estate or personal property.
Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil, NGLs, or other liquid hydrocarbons.
Bcf. Billion cubic feet, used in reference to natural gas.
BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.
BTU. One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.
Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.
Developed reserves. Reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry hole. A well found to be incapable of producing either oil, natural gas, and/or NGLs in commercial quantities.
Exploratory well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir beyond its known horizon.
Fee properties. The most extensive interest that can be owned in land, including surface and mineral (including oil and natural gas) rights.
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.
Finding and development cost. Expressed in dollars per BOE. Finding and development cost metrics provide information as to the cost of adding proved reserves from various activities, and are widely utilized within the exploration and production industry, as well as by investors and analysts. The information used to calculate these metrics is included in the Supplemental Oil and Gas Information section in Part II, Item 8 of this report. It should be noted that finding and development cost metrics have limitations. For example, exploration efforts related to a particular set of proved reserve additions may extend over several years. As a result, the exploration costs incurred in earlier periods are not included in the amount of exploration costs incurred during the period in which that set of proved reserves is added. In addition, consistent with industry practice, future capital costs to develop proved undeveloped reserves are not included in costs incurred. Since the additional development costs that will need to be

incurred in the future before the proved undeveloped reserves are ultimately produced are not included in the amount of costs incurred during the period in which those reserves were added, those development costs in future periods will be reflected in the costs associated with adding a different set of reserves. The calculations of various finding and development cost metrics are explained below.

Finding and development cost – Drilling, excluding revisions. Calculated by dividing the amount of costs incurred for development and exploration activities, by the amount of estimated net proved reserves added through discoveries, extensions, and infill drilling, during the same period.

Finding and development cost – Drilling, including revisions. Calculated by dividing the amount of costs incurred for development and exploration activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, and revisions of previous estimates, during the same period.

Finding and development cost – Drilling and acquisitions, excluding revisions. Calculated by dividing the amount of costs incurred for development, exploration, and acquisition of proved properties, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, and acquisitions, during the same period.

Finding and development cost – Drilling and acquisitions, including revisions. Calculated by dividing the amount of costs incurred for development, exploration, and acquisition of proved properties, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates, during the same period.

Finding and development cost – All in, including sales of reserves. Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates less sales of reserves, during the same period.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Frac spread. Hydraulic fracturing requires custom-designed and purpose-built equipment. A “frac spread” is the equipment necessary to carry out a fracturing job.

Gross acre. An acre in which a working interest is owned.

Gross well. A well in which a working interest is owned.

Horizontal wells. Wells that are drilled at angles greater than 70 degrees from vertical.

Lease operating expenses. The expenses incurred in the lifting of crude oil, natural gas, and/or associated liquids from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition, drilling, or completion costs.

MBbl. One thousand barrels of crude oil, NGLs, or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet, used in reference to natural gas.

MCFE. One thousand cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

MMBbl. One million barrels of oil, NGLs, or other liquid hydrocarbons.

MMBOE. One million barrels of oil equivalent.
MMBtu. One million British thermal units.
MMcf. One million cubic feet, used in reference to natural gas.
Net acres or net wells. Sum of our fractional working interests owned in gross acres or gross wells.
Net asset value per share. The result of the fair market value of total assets less total liabilities, divided by the total number of outstanding shares of common stock.
NGLs. The combination of ethane, propane, butane, and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
NYMEX WTI. New York Mercantile Exchange West Texas Intermediate, a common industry benchmark price for crude oil.
NYMEX Henry Hub. New York Mercantile Exchange Henry Hub, a common industry benchmark price for natural gas.
OPIS. Oil Price Information Service, a common industry benchmark for NGL pricing at Mont Belvieu, Texas.
PV-10 (Non-GAAP). The present value of estimated future revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period. This is a non-GAAP measure.
Productive well. A well that is producing crude oil, natural gas, and/or NGLs or that is capable of commercial production of those products.
Proved reserves. Those quantities of oil, gas, and NGLs 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
Recompletion. The completion of an existing wellbore in a formation other than that in which the well has previously been completed.
Reserve life. Expressed in years, represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

Reserve replacement. Reserve replacement metrics are used as indicators of a company's ability to replenish annual production volumes and grow its reserves, and provide information related to how successful a company is at growing its proved reserve base. These are believed to be useful non-GAAP measures that are widely utilized within the exploration and production industry, as well as by investors and analysts. They are easily calculable metrics, and the information used to calculate these metrics is included in the Supplemental Oil and Gas Information section of Part II, Item 8 of this report. It should be noted that reserve replacement metrics have limitations. They are limited because they typically vary widely based on the extent and timing of new discoveries and property acquisitions. Their predictive and comparative value is also limited for the same reasons. In addition, because the metrics do not embed the cost or timing of future production of new reserves, they cannot be used as a measure of value creation. The calculations of various reserve replacement metrics are explained below.

Reserve replacement – Drilling, excluding revisions. Calculated as a numerator comprised of the sum of reserve extensions and discoveries and infill reserves in an existing proved field divided by production for the same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity.

Reserve replacement – Drilling, including revisions. Calculated as a numerator comprised of the sum of reserve extensions, discoveries, infill reserves, and revisions of previous estimates in an existing proved field divided by production for the same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity with an adjustment for revisions.

Reserve replacement – Drilling and acquisitions, excluding revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions, discoveries, and infill reserves in an existing proved field divided by production for the same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities.

Reserve replacement – Drilling and acquisitions, including revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions, discoveries, infill reserves, and revisions of previous estimates in an existing proved field divided by production for the same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities with an adjustment for revisions.

Reserve replacement – All in, excluding sales of reserves. The sum of reserve extensions and discoveries, infill drilling, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for the same period.

Reserve replacement –All in, including sales of reserves. The sum of sales of reserves, infill drilling, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.

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

Resource play. A term used to describe an accumulation of crude oil, natural gas, and/or associated liquid resources known to exist over a large areal expanse, which when compared to a conventional play typically has lower expected geological risk.

Royalty. The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil, natural gas, and NGLs produced and sold unencumbered by expenses relating to the drilling, completing, and operating of the affected well.

Royalty interest. An interest in an oil and natural gas property entitling the owner to shares of crude oil, natural gas, and NGL production free of costs of exploration, development, and production operations.
Seismic. The sending of energy waves or sound waves into the earth and analyzing the wave reflections to infer the type, size, shape, and depth of subsurface rock formations.
Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.
Standardized measure of discounted future net cash flows. The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, and a 10 percent annual discount rate. The information for this calculation is included in Supplemental Oil and Gas Information located in Part II, Item 8 of this report.
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, natural gas, and associated liquids regardless of whether such acreage contains estimated net proved reserves.
Undeveloped reserves. 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 applicable SEC definition of undeveloped reserves provides that undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.
Working interest. The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production, sales, and costs.

ITEM 1A. RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in us.

Risks Related to Our Business

Crude oil, natural gas, and NGL prices are volatile, and declines in prices adversely affect our profitability, financial condition, cash flows, access to capital, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and natural gas properties depend heavily on the prices we receive for crude oil, natural gas and NGL sales. Crude oil, natural gas, and NGL prices also affect our cash flows available for capital expenditures and other items, our borrowing capacity, and the volume and amount of our crude oil, natural gas, and NGL reserves. For example, the amount of our borrowing base under our credit facility is subject to periodic redeterminations based on crude oil, natural gas, and NGL prices specified by our bank group at the time of redetermination. In addition, we may have crude oil and natural gas property impairments or downward revisions of estimates of proved reserves if prices fall significantly.

Historically, the markets for crude oil, natural gas, and NGLs have been volatile, and they are likely to continue to be volatile. Wide fluctuations in crude oil, natural gas, and NGL prices may result from relatively minor changes in the supply of and demand for crude oil, natural gas, and NGLs, market uncertainty, and other factors that are beyond our control, including:

- global and domestic supplies of crude oil, natural gas, and NGLs, and the productive capacity of the industry as a whole;
- the level of consumer demand for crude oil, natural gas, and NGLs;
- overall global and domestic economic conditions;
- weather conditions;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities in regional or localized areas that may affect the realized price for crude oil, natural gas, or NGLs;
- liquefied natural gas deliveries to and from the United States;
- the price and level of imports and exports of crude oil, refined petroleum products, and liquefied natural gas;
- the price and availability of alternative fuels;
- technological advances and regulations affecting energy consumption and conservation;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting countries to agree to and maintain crude oil price and production controls;
- political instability or armed conflict in crude oil or natural gas producing regions;
- strengthening and weakening of the United States dollar relative to other currencies; and
- governmental regulations and taxes.

These factors and the volatility of crude oil, natural gas, and NGL markets make it extremely difficult to predict future crude oil, natural gas, and NGL price movements with any certainty. Declines in crude oil, natural gas, and NGL prices would reduce our revenues and could also reduce the amount of crude oil, natural gas, and NGLs that we can produce economically, which could have a materially adverse effect on us.

Weakness in economic conditions or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

In recent years, the United States and global economies and financial systems have experienced turmoil and upheaval characterized by extreme volatility in prices of equity and debt securities, periods of diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse, or sale of financial institutions, increased levels of unemployment, and an unprecedented level of intervention by the United States federal government and other governments. Although the United States economy appears to have stabilized, the extent and timing of a recovery, and whether it can be sustained, are uncertain. Renewed weakness in the United States or other large economies could materially adversely affect our business and financial condition. For example:

- crude oil, NGL and natural gas prices have recently been lower than at various times in the last decade because of increased supply resulting from, among other things, increased drilling in unconventional reservoirs, leading to lower revenues, which could affect our financial condition and results of operations;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables;
- the liquidity available under our credit facility could be reduced if any lender is unable to fund its commitment;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business, including for the exploration and/or development of reserves;
- our commodity derivative contracts could become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection; and
- variable interest rate spread levels, including for LIBOR and the prime rate, could increase significantly, resulting in higher interest costs for unhedged variable interest rate based borrowings under our credit facility.

If we are unable to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find, develop, or acquire crude oil, natural gas, and NGL reserves that are economically producible. Our properties produce crude oil, natural gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate and develop or acquire new crude oil, natural gas, and NGL reserves to replace those being depleted by production. Without successful drilling or acquisition activities, our reserves and production will decline over time. In addition, competition for crude oil and natural gas properties is intense, and many of our competitors have financial, technical, human, and other resources necessary to evaluate and integrate acquisitions that are substantially greater than those available to us.

In the event we do complete an acquisition, its successful impact on our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price for the acquisition, future crude oil, natural gas, and NGL prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties, and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems. Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Substantial capital is required to develop and replace our reserves.

We must make substantial capital expenditures to find, acquire, develop, and produce crude oil, natural gas, and NGL reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, prices received for crude oil, natural gas, and NGL sales, our success in locating and developing and acquiring new reserves, and the orderly functioning of credit and capital markets. If crude oil, natural gas, and NGL prices decrease or if we encounter operating difficulties that result in our cash flows from operations being less than expected, we may reduce our planned capital expenditures unless we can raise additional funds through debt or equity financing or the divestment of assets. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms, and the proceeds offered to us for potential divestitures may not always be of acceptable value to us.

If our revenues decrease due to lower crude oil, natural gas, or NGL prices, decreased production, or other reasons, and if we cannot obtain funding through our credit facility, other acceptable debt or equity financing arrangements, or through the sale of assets, our ability to execute development plans, replace our reserves, maintain our acreage, or maintain production levels could be greatly limited.

Competition in our industry is intense, and many of our competitors have greater financial, technical, and human resources than we do.

We face intense competition from major oil and gas companies, independent oil and gas exploration and production companies, and institutional and individual investors who seek oil and gas investments throughout the world, as well as the equipment, expertise, labor, and materials required to operate crude oil and natural gas properties. Many of our competitors have financial, technical, and other resources exceeding those available to us, and many crude oil and natural gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for exploratory and development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for properties. We may not be successful in acquiring and developing profitable properties in the face of this competition. In addition, other companies may have a greater ability to continue drilling activities during periods of low natural gas or oil prices and to absorb the burden of current and future governmental regulations and taxation. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. Also, we compete for human resources. Over the last few years, the need for talented people across all disciplines in the industry has grown, while the number of talented people available has not grown at the same pace, and in many cases, is declining due to the demographics of the industry. Our inability to compete effectively with companies in any area of our business could have a material adverse impact on our business activities, financial condition and results of operations.

The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

The actual quantities and present value of our proved crude oil, natural gas, and NGL reserves may be less than we have estimated.

This report and other of our SEC filings contain estimates of our proved crude oil, natural gas, and NGL reserves and the estimated future net revenues from those reserves. These estimates are based on various assumptions, including assumptions required by the SEC relating to crude oil, natural gas, and NGL prices, drilling and completion costs, gathering and transportation costs, operating expenses, capital expenditures, effects of governmental regulation, taxes, timing of operations, and availability of funds. The process of estimating crude oil, natural gas, and NGL reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. These estimates are dependent on many variables, and changes often occur as our knowledge of these variables evolve. Therefore, these estimates are inherently imprecise. In addition, the reserve estimates we make for properties that do not have a significant production history may be less reliable than estimates for properties with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates, and the timing and/or amount of development expenditures.

Actual future production, prices for crude oil, natural gas, and NGLs, revenues, production taxes, development expenditures, operating expenses, and quantities of producible crude oil, natural gas, and NGL reserves will most likely vary from those estimated. Any significant variance of any nature could materially affect the estimated quantities of and present value related to proved reserves disclosed by us, and the actual quantities and present value may be significantly less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration, operations and development activity, prevailing crude oil, natural gas, and NGL prices, costs to develop and operate properties, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties, which we may not control.

As of December 31, 2014, 48 percent, or 260.9 MMBOE, of our estimated proved reserves were proved undeveloped, and three percent, or 17.2 MMBOE, were proved developed non-producing. In order to develop our proved undeveloped reserves, as of December 31, 2014, we estimate approximately $3.1 billion of capital expenditures would be required. Production revenues from proved developed non-producing reserves will not be realized until sometime in the future and after some investment of capital. In order to develop our proved developed non-producing reserves, as of December 31, 2014, we estimate capital expenditures of approximately $29 million would be required. Although we have estimated our proved reserves and the costs associated with these proved reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled, and actual results may not occur as estimated.

You should not assume that the PV-10 and standardized measure of discounted future net cash flows included in this report represent the current market value of our estimated proved crude oil, natural gas, and NGL reserves.
Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. For example, the present value of our proved reserves as of December 31, 2014, was estimated using a calculated 12-month average sales price of $4.35 per MMBtu of natural gas (NYMEX Henry Hub spot price), $94.99 per Bbl of oil (NYMEX WTI spot price), and $39.91 per Bbl of NGL (OPIS spot price). We then adjust these prices to reflect appropriate basis, quality, and location differentials over the period in estimating our proved reserves. During 2014, our monthly average realized natural gas prices, excluding the effect of derivative settlements, were as high as $5.78 per Mcf and as low as $3.69 per Mcf. For the same period, our monthly average realized crude oil prices before the effect of derivative settlements were as high as $94.36 per Bbl and as low as $50.22 per Bbl, and were as high as $42.83 per Bbl and as low as $19.94 per Bbl for NGLs. Many other factors will affect actual future net cash flows, including:

- amount and timing of actual production;
- supply and demand for crude oil, natural gas, and NGLs;
- curtailments or increases in consumption by oil purchasers and natural gas pipelines; and
- changes in government regulations or taxes, including severance and excise taxes.

The timing of production from oil and natural gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing PV-10. In addition, the 10 percent discount factor required by the SEC to be used to calculate PV-10 for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates, costs of capital, and other risks to which our business and the oil and natural gas industry in general are subject.
Our property acquisitions may not be worth what we paid due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.
Successful property acquisitions require an assessment of a number of factors, some of which are beyond our control. These factors include exploration potential, future crude oil, natural gas, and NGL prices, operating costs, and potential environmental and other liabilities. These assessments are not precise and their accuracy is inherently uncertain.
In connection with our acquisitions, we typically perform a customary review of the acquired properties that will not necessarily reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well, we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties.
In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such acquisitions may be limited.

Integrating acquired properties and businesses involves a number of other special risks, including the risk that management may be distracted from normal business concerns by the need to integrate operations and systems as well as retain and assimilate additional employees. Therefore, we may not be able to realize all of the anticipated benefits of our acquisitions.

We have limited control over the activities on properties we do not operate.

Some of our properties, including a portion of our interests in the Eagle Ford shale in south Texas, are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including the nature and timing of drilling and operational activities, the operator's skill and expertise, compliance with environmental, safety and other regulations, the approval of other participants in such properties, the selection and application of suitable technology, or the amount of expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the expenditures of such properties. These limitations and our dependence on the operator and other working interest owners in these projects could cause us to incur unexpected future costs and materially and adversely affect our financial condition and results of operations.

We rely on third-party service providers to conduct drilling and completion and other related operations on properties we operate.

Where we are the operator of a property, we rely on third-party service providers to perform necessary drilling and completion and other related operations. The ability of third-party service providers to perform such operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, natural gas, and NGLs prevailing economic conditions and financial, business and other factors. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the property and adversely affect our financial condition and results of operations.

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

We generally rely on title reports in acquiring oil and gas leasehold interests and obtain title opinions only on significant properties that we drill. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Title insurance is not available for oil and gas properties. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and title abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. Generally, under the terms of the operating agreements affecting our properties, any monetary loss attributable to a loss of title is to be borne by all parties to any such agreement in proportion to their interests in such property. A material title defect can reduce the value of a property or render it worthless, thus adversely affecting our financial condition, results of operations and operating cash flow if such property is of sufficient value.

Exploration and development drilling may not result in commercially producible reserves.

Crude oil and natural gas drilling, completion and production activities are subject to numerous risks, including the risk that no commercially producible crude oil, natural gas, or associated liquids will be found. The cost of drilling and completing wells is often uncertain, and crude oil, natural gas or associated liquids drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected adverse drilling or completion conditions;
- title problems;
- disputes with owners or holders of surface interests on or near areas where we operate;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- hurricanes, tornadoes, flooding, or other adverse weather conditions;
- governmental permitting delays;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, water, sand, and other supplies.

The prevailing prices for crude oil, natural gas, and NGLs affect the cost of and the demand for drilling rigs, completion and production equipment, and other related services. However, changes in costs may not occur simultaneously with corresponding changes in commodity prices. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the available rigs in that region.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a materially adverse effect on our ability to explore or develop our properties.

The wells we drill may not be productive, and we may not recover all or any portion of our investment in such wells.

The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if crude oil, natural gas, or NGLs are present, or whether they can be produced economically. The cost of drilling, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover drilling and completion costs. Even if sufficient amounts of crude oil, natural gas, or NGLs exist, we may damage a potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing a well, which could result in reduced or no production from the well, significant expenditure to repair the well, and/or the loss and abandonment of the well.

Results in our newer resource plays may be more uncertain than results in resource plays that are more developed and have longer established production histories. For example, industry experience and knowledge in the Eagle Ford shale play, is more limited compared to more established resource plays, such as the Barnett or Woodford shales, and we and the industry generally have less information with respect to the ultimate recoverability of reserves and the production decline rates in newer resource plays than other areas with longer histories of development and production. Drilling and completion techniques that have proven to be successful in other resource plays are being used in the early development of these new plays; however, we can provide no assurance of the ultimate success of these drilling and completion techniques.

In addition, a significant part of our strategy involves increasing our inventory of drilling locations. Such multi-year drilling inventories can be more susceptible to long-term uncertainties that could materially alter the occurrence or timing of actual drilling. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled, although we have the present intent to do so for locations booked as proved undeveloped locations, or if we will be able to produce crude oil, natural gas, or NGLs from these potential drilling locations.

Our future drilling activities may not be successful. Our overall drilling success rate or our drilling success rate within a particular area may decline. In addition, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Unless production is established within the spacing units covering undeveloped acres on which our drilling locations are identified, the leases for such acreage will expire and we would lose our right to develop the related properties. Our total net acreage expiring in the next three years represents approximately 41 percent of our total net undeveloped acreage at December 31, 2014. Although we have identified numerous potential drilling locations, we may not be able to economically produce crude oil, natural gas, or NGLs from all of them and our actual drilling activities may materially differ from those presently identified, which could adversely affect our financial condition, results of operations and operating cash flow.

Part of our strategy involves drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory and delineation drilling in these plays are subject to drilling and completion technique risks, and results may not meet our expectations for reserves or production. As a result, we may incur material write-downs, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Many of our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize production and ultimate recoveries and therefore generate the highest possible returns. Risks we face while drilling include, but are not limited to, landing our well bore outside the desired drilling zone, deviating from the desired drilling zone while drilling horizontally through the formation, the inability to run our casing the entire length of the well bore, and the inability to run tools and recover equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, the inability to fracture stimulate the planned number of stages, the inability to run tools and other equipment the entire length of the well bore during completion operations, the inability to recover such tools and other equipment, and the inability to successfully clean out the well bore after completion of the final fracture stimulation.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and takeaway capacity, and/or prices for crude oil, natural gas, and NGLs decline, then the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of oil and gas properties and the value of our undeveloped acreage could decline in the future.

Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.

We inject water into formations on some of our properties to increase the production of crude oil, natural gas, and associated liquids. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of crude oil, natural gas, and associated liquids in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. In addition, if proposed legislation and regulatory initiatives relating to hydraulic fracturing become law, the cost of some of these enhanced recovery methods could increase substantially.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids towards the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Our commodity derivative contract activities may result in financial losses or may limit the prices we receive for crude oil, natural gas, and NGL sales.

To mitigate a portion of the exposure to potentially adverse market changes in crude oil, natural gas, and NGL prices and the associated impact on cash flows, we have entered into various derivative contracts. Our derivative contracts in place include swap and collar arrangements for crude oil, natural gas, and NGLs. As of December 31, 2014, we were in a net accrued asset position of $592.1 million with respect to our crude oil, natural gas, and NGL derivative activities. These activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- one or more counterparties to our commodity derivative contracts default on their contractual obligations; or
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative contract arrangement.

The risk of one or more counterparties defaulting on their obligations is heightened by the recent decline in crude oil, natural gas, and NGL prices. These circumstances may adversely affect the ability of our counterparties to meet their obligations to us pursuant to derivative transactions, which could reduce our revenues and cash flows from derivative settlements. As a result, our financial condition, results of operations, and cash flows could be materially affected in an adverse way if our counterparties default on their contractual obligations under our commodity derivative contracts.

In addition, commodity derivative contracts may limit the prices we receive for our crude oil, natural gas and NGL sales if crude oil, natural gas, or NGL prices rise substantially over the price established by the commodity derivative contract.

The inability of customers or co-owners of assets to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from crude oil, natural gas, and NGL sales or joint interest billings to co-owners of oil and gas properties we operate. This concentration of customers and joint interest owners may impact our overall credit risk because these entities may be similarly affected by various economic and other conditions, including the recent decrease in crude oil prices. The loss of one or more of these customers could reduce competition for our products and negatively impact the prices of commodities we sell. The Company does not believe the loss of any single purchaser would materially impact its operating results, as the Company has numerous options for purchasers in each of its operating regions for its crude oil, natural gas, and NGL production. Please refer to Note 1 - Summary of Significant Accounting Policies, under the heading Concentration of Credit Risk and Major Customers in Part II, Item 8 of this report for further discussion of our concentration of credit risk and major customers.

We have entered into firm transportation contracts that require us to pay fixed amounts of money to our counterparties regardless of quantities actually shipped, processed, or gathered. If we are unable to deliver the necessary quantities of natural gas to our counterparties, our results of operations and liquidity could be adversely affected.

As of December 31, 2014, we were contractually committed to deliver 1,411 Bcf of natural gas and 48 MMBbl of crude oil pursuant to contracts expiring at various dates through 2028. We may enter into additional firm transportation agreements as our development of our resource plays expands. At the current time, we do not have enough proved developed reserves to offset these contractual liabilities, but we intend to develop reserves that will exceed the commitments and therefore do not expect any material shortfalls. In the event we encounter delays in drilling and completing our wells or otherwise due to construction, interruptions of operations, or delays in connecting new volumes to gathering systems or pipelines for an extended period of time, the requirements to pay for quantities not delivered could have a material impact on our results of operations and liquidity.

Future crude oil, natural gas, and NGL price declines or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our crude oil and natural gas properties. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If commercial quantities of hydrocarbons are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our oil and gas properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net revenues, we generally must write down the costs of each depletion pool to the estimated discounted future net cash flows of that depletion pool. Unproved properties are evaluated at the lower of cost or fair market value. We incurred impairment of proved properties and impairment of unproved properties totaling $84.5 million and $75.6 million, respectively, during 2014, $172.6 million and $46.1 million, respectively, during 2013, and $208.9 million and $16.3 million, respectively, during 2012. Commodity prices significantly declined in 2014. Continued declines in the prices of crude oil, natural gas, or NGLs or unsuccessful exploration efforts could cause additional proved and/or unproved property impairments in the future.

We review the carrying value of our properties for indicators of impairment on a quarterly basis using the prices in effect as of the end of each quarter. Once incurred, a write-down of oil and natural gas properties cannot be reversed at a later date, even if crude oil, natural gas, or NGL prices increase.

Lower crude oil, natural gas, or NGL prices could limit our ability to borrow under our credit facility.
Our credit facility has a current commitment amount of $1.5 billion, subject to a borrowing base that the lenders redetermine semi-annually based on the bank group's assessment of the value of our crude oil and natural gas properties, which in turn is impacted by crude oil, natural gas, and NGL prices. The current borrowing base under our credit facility is $2.4 billion. The prices of crude oil and NGLs declined significantly beginning in mid-2014 and declined further subsequent to December 31, 2014. These declines in the prices of crude oil and NGLs, or significant declines in natural gas prices in the future could limit our borrowing base and reduce the amount we can borrow under our credit facility. Our amendment to our credit facility in 2014 specified that the borrowing base was not reduced by the issuance of the 6.125% Senior Notes due 2022 ("2022 Notes") that we issued on November 17, 2014, and will remain at $2.4 billion until the next scheduled redetermination date of April 1, 2015. Additionally, divestitures of properties or other bond offerings could result in a reduction of our borrowing base.
The amount of our debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt.
As of December 31, 2014, we had $350.0 million of long-term senior unsecured debt outstanding relating to our 6.625% Senior Notes due 2019 (the "2019 Notes") that we issued on February 7, 2011; $350.0 million of long-term senior unsecured debt outstanding relating to our 6.50% Senior Notes due 2021 (the "2021 Notes") that we issued on November 8, 2011; $600.0 million of long-term senior unsecured debt outstanding relating to our 2022 Notes that we issued on November 17, 2014; $400.0 million of long-term senior unsecured debt outstanding relating to our 6.50% Senior Notes due 2023 (the "2023 Notes") that we issued on June 29, 2012; and $500.0 million of long-term senior unsecured debt outstanding relating to our 5.0% Senior Notes due 2024 (the "2024 Notes") that we issued on May 20, 2013 (collectively, the 2019 Notes, the 2021 Notes, the 2022 Notes, the 2023 Notes, and the 2024 Notes are referred to as our "Senior Notes"); and $166.0 million of outstanding borrowings under our secured credit facility. We had three outstanding letters of credit in the aggregate amount of $808,000 (which reduce the amount available for borrowing under the facility on a dollar-for-dollar basis), resulting in $1.3 billion of available debt capacity under our credit facility, assuming the borrowing conditions under this facility will be met. Our long-term debt represented 51 percent of our total book capitalization as of December 31, 2014.
Our indebtedness could have important consequences for our operations, including:

- making it more difficult for us to obtain additional financing in the future for our operations and potential acquisitions, working capital requirements, capital expenditures, debt service, or other general corporate requirements;
- requiring us to dedicate a substantial portion of our cash flows from operations to the repayment of our debt and the service of interest costs associated with our debt, rather than to productive investments;
- limiting our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making acquisitions, and paying dividends;
- placing us at a competitive disadvantage compared to our competitors with less debt; and
- making us more vulnerable in the event of adverse economic or industry conditions or a downturn in our business.

Our ability to make payments on our debt, refinance our debt, and fund planned capital expenditures will depend on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory, and other factors that are beyond our control. If our business does not generate sufficient cash flow from operations or future sufficient borrowings are not available to us under our credit facility or from other sources, we might not be able to service our debt or fund our other liquidity needs. If we are unable to service our debt, due to inadequate liquidity or otherwise, we may have to delay or cancel acquisitions, defer capital expenditures, sell equity securities, divest assets, and/or restructure or refinance our debt. We might not be able to sell our equity, sell our assets, or restructure or refinance our debt on a timely basis or on satisfactory terms or at all. In addition, the terms of our existing or future debt agreements, including our existing and future credit agreements, may prohibit us from pursuing any of these alternatives. Further, changes in the credit ratings of our debt may negatively affect the cost, terms, conditions, and availability of future financing.

Our debt agreements, including the agreement governing our credit facility and the indentures governing the Senior Notes, permit us to incur additional debt in the future, subject to compliance with restrictive covenants under those agreements. In addition, entities we may acquire in the future could have significant amounts of debt outstanding that we could be required to assume, and in some cases accelerate repayment thereof, in connection with the acquisition, or we may incur our own significant indebtedness to consummate an acquisition.

As discussed above, our credit facility is subject to periodic borrowing base redeterminations. We could be forced to repay a portion of our bank borrowings in the event of a downward redetermination of our borrowing base, and we may not have sufficient funds to make such repayment at that time. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowing base or arrange new financing, we may be forced to sell significant assets.

The agreements governing our debt contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.

Our debt agreements contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under our credit facility is subject to compliance with certain financial covenants, including (i) maintenance of a quarterly ratio of total debt to 12-month trailing consolidated adjusted earnings before interest, taxes, depreciation, amortization, and exploration expense of less than 4.0, and (ii) maintenance of an adjusted current ratio of no less than 1.0, each as defined in our credit facility. Our credit facility also requires us to comply with certain financial covenants, including requirements that we maintain certain levels of stockholders' equity and limit our annual cash dividends to no more than $50.0 million. These restrictions on our ability to operate our business could seriously harm our business by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

The respective indentures governing the Senior Notes also contain covenants that, among other things, limit our ability and the ability of our subsidiaries to:

- incur additional debt;
- make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem, or retire capital stock;
- sell assets, including capital stock of our subsidiaries;
- restrict dividends or other payments of our subsidiaries;
- create liens that secure debt;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all or a portion of our indebtedness. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

We are subject to operating and environmental risks and hazards that could result in substantial losses or liabilities that may not be fully insured.

Oil and gas operations are subject to many risks, including human error and accidents, that could cause personal injury, death, property damage, well blowouts, craterings, explosions, uncontrollable flows of crude oil, natural gas and associated liquids or well fluids, releases or spills of completion fluids, spills or releases from facilities and equipment used to deliver or store these materials, spills or releases of brine or other produced or flowback water, subsurface conditions that prevent us from stimulating the planned number of completion stages, accessing the entirety of the wellbore with our tools during completion, or removing materials from the wellbore to allow production to begin, fires, adverse weather such as hurricanes or tornadoes, freezing conditions, floods, droughts, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas such as hydrogen sulfide, and other environmental risks and hazards. If any of these types of events occurs, we could sustain substantial losses.

Furthermore, if we experience any of the problems with well stimulation and completion activities referenced above, our ability to explore for and produce crude oil, natural gas, or NGLs may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of the need to shutdown, abandon or relocate drilling operations, the need to modify drill sites to lessen the risk of spills or releases, the need to investigate and/or remediate any spills, releases or ground water contamination that might have occurred, and the need to suspend our operations.

There is inherent risk of incurring significant environmental costs and liabilities in our operations due to our current and past generation, handling and disposal of materials, including solid and hazardous wastes and petroleum hydrocarbons. We may incur joint and several, strict liability under applicable United States federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from our leased or owned properties, some of which have been used for natural gas and oil exploration and production activities for a number of years, often by third parties not under our control. For our outside operated properties, we are dependent on the operator for operational and regulatory compliance, and could be subject to liabilities in the event of non-compliance. These properties and the wastes disposed thereon or away from could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including the CERCLA or the Superfund law, the RCRA, the Clean Water Act, the CAA, the OPA, and analogous state laws. Under any implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damage allegedly caused by the release of petroleum hydrocarbons or other hazardous substances into the environment. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We have significant but limited coverage for sudden environmental damage. We do not believe that insurance coverage for the full potential liability that could be caused by environmental damage that occurs gradually over time is appropriate for us at this time given the nature of our operations and the nature and cost of such coverage. Further, we may elect not to obtain insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks to which we are subject. Accordingly, we may be subject to liability or may lose substantial assets in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, we could suffer a material loss.

Our operations are subject to complex laws and regulations, including environmental regulations that result in substantial costs and other risks.

Federal, state, tribal, and local authorities extensively regulate the oil and natural gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing or marketing of crude oil, natural gas and NGL production. Noncompliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead to substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations and may also result in the suspension or termination of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, and abandon wells and related facilities and, in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for and the production of crude oil, natural gas, and NGLs, including the permit and bonding requirements of drilling wells, the spacing of wells, the unitization or pooling of interests in crude oil and natural gas properties, rights-of-way and easements, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, and restoration standards, oil and gas operations, and restoration. Public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit or right-of-way grant or impose conditions of approval to mitigate potential environmental impacts, which could, in either case, negatively affect our ability to explore or develop certain properties. Federal authorities also may require any of our ongoing or planned operations on federal leases to be delayed, suspended, or terminated. Any such delay, suspension, or termination could have a materially adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, tribal and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, including the designation of previously unprotected wildlife or plant species as threatened or endangered in areas we operate, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several, strict liability under federal, state, and tribal environmental laws for noise emissions and for discharges of crude oil, natural gas, and associated liquids or other pollutants into the air, soil, surface water, or groundwater. We could be required to spend substantial amounts on investigations, litigation, and remediation for these emissions and discharges and other compliance issues. Any unpermitted release of petroleum or other pollutants from our operations could result not only in cleanup costs, but also natural resources, real or personal property and other damages and civil and criminal liabilities. The listing of additional wildlife or plant species as federally endangered or threatened could result in limitations on exploration and production activities in certain locations. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a materially adverse effect on us.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Operations in certain of our regions, such as our Rocky Mountain and Permian regions, are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife or plant species. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic

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shortages. Wildlife seasonal restrictions may limit access to federal leases or across federal lands. Possible restrictions may include seasonal restrictions in greater sage-grouse habitat during breeding and nesting seasons, within a certain distance of active raptor nests during fledging, and in big game winter or parturition ranges during winter or calving seasons. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and NGLs from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Eagle Ford shale of south Texas and the Bakken/Three Forks formations in North Dakota. Hydraulic fracturing involves using water, sand and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions. However, the EPA and other federal agencies have asserted federal regulatory authority over certain aspects of hydraulic fracturing activities as outlined below.

The EPA has authority to regulate underground injections that contain diesel in the fluid system under the SDWA. The EPA has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. The EPA also plans to update its chloride water quality criteria for the protection of aquatic life under the Clean Water Act. Flowback and produced water from the hydraulic fracturing process contain total dissolved solids, including chlorides, and regulation of these fluids could be affected by the new criteria. The EPA has delayed issuing a draft criteria document until 2015. The EPA has also announced that it will develop pre-treatment standards for disposal of wastewater produced from shale gas operations through publicly owned treatment works. The regulations will be developed under the EPA’s Effluent Guidelines Program under the authority of the Clean Water Act. The EPA anticipates issuing the proposed rules in 2015. If the EPA implements further regulations of hydraulic fracturing, 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 could even be prohibited from drilling and/or completing certain wells.

Certain states in which we operate, including Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, 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 and the public of certain information regarding the components and volume of water used in the hydraulic fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. Recently, several municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries, setting the stage for challenges by state regulators and third-parties. Similar events and processes are playing out in several cities, counties, and townships across the United States. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, 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 could even be prohibited from drilling and/or completing certain wells.

Several agencies of the federal governmental are actively involved in studies or reviews that focus on environmental aspects and impacts of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating a review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices and government studies related thereto. 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

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environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA issued a progress report in 2012, and plans to issue a draft report of results in 2015 for public comment, following release of peer reviewed papers in late 2014 and early 2015. The United States Department of Energy is actively involved in research on hydraulic fracturing practices, including groundwater protection. Also, the United States Department of the Interior proposed a rule to regulate hydraulic fracturing on public lands in May of 2013. The proposed rule contains disclosure requirements and other mandates for well integrity and management of water produced by the process, and is under review by the Office of Management and Budget.

Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. If hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit or disclosure requirements, associated permitting delays, operational restrictions, litigation risk and potential cost increases. Additionally, certain members of Congress have called upon the United States Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, 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 the United States 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. The United States Geological Survey Offices of Energy Resources Program, Water Resources and Natural Hazards and Environmental Health Offices also have ongoing research projects on hydraulic fracturing. These ongoing studies, depending on their course and outcomes, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory processes.

Further, on August 16, 2012, the EPA issued final rules subjecting all new and modified oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards (“NSPS”) and all existing and new operations to the National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. The EPA rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards require the use of reduced emission completion (“REC”) techniques developed in the EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line beginning in January 2015. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAP include maximum achievable control technology (“MACT”) standards for those glycol dehydrators and certain storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. These rules will require additional control equipment, changes to procedure, and extensive monitoring and reporting. The EPA stated in January 2013, however, that it intends to reconsider portions of the final rule. On September 23, 2013, the EPA published new standards for storage tanks subject to the NSPS. In December 2014, the EPA finalized additional updates to the 2012 NSPS. The amendments clarified stages for flowback and the point at which green completion equipment is required and updated requirements for storage tanks and leak detection requirements for processing plants. The EPA has stated that it continues to review other issues raised in petitions for reconsideration. We are currently evaluating the effect of these rules on our business.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing such activities to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. Over the past year, several court cases have addressed aspects of hydraulic fracturing. In a case that could delay operations on public lands, a court in California held that the BLM did not adequately consider the impact of hydraulic fracturing and horizontal drilling before issuing leases. Courts in New York and Colorado reduced the level of evidence required before a court will agree to consider alleged damage claims from hydraulic fracturing by property owners. Litigation resulting in financial compensation for damages linked to hydraulic fracturing could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to

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increased regulation, permitting requirements, enforcement actions, and penalties. Additional legislation or regulation could also lead to operational delays or restrictions or increased costs in the exploration for and production of oil, natural gas, and associated liquids, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state, or local laws, or the implementation of new regulations, regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.
Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.
The hydraulic fracturing process on which we and others in our industry depend to complete wells that will produce commercial quantities of crude oil, natural gas, and NGLs requires the use and disposal of significant quantities of water.
Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of crude oil, natural gas, and NGLs.
Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.
Certain United States 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.

Recent federal budget proposals, if enacted into law, would eliminate certain key United States federal income tax incentives currently available to oil and natural gas exploration and production companies. These potential changes include:

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

It is unclear when or if these or similar changes will be enacted. The passage of legislation enacting these or similar changes in 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.
Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil, natural gas, and NGLs.
In December 2009, the EPA made a finding that emissions of carbon dioxide, methane, and other “greenhouse gases” endanger public health and the environment because emissions of such gases contribute to

warming of the earth's atmosphere and other climatic changes. Based on this finding, the EPA has over the past four years adopted and implemented a comprehensive suite of regulations to restrict and otherwise regulate emissions of greenhouse gases under existing provisions of the CAA. In particular, the EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA. One rule requires a reduction in greenhouse gas emissions from motor vehicles, and the other regulates permitting and greenhouse gas emissions from certain large stationary sources. These EPA regulatory actions have been challenged by various industry groups, initially in the D.C. Circuit, which in 2012 ruled in favor of the EPA in all respects. However, in June 2014, the United States Supreme Court reversed the D.C. Circuit and struck down the EPA's greenhouse gas permitting rules to the extent they impose a requirement to obtain a permit based solely on emissions of greenhouse gases. However, large sources of air pollutants other than greenhouse gases would still be required to implement the best available capture technology for greenhouse gases. The EPA has also adopted reporting rules for greenhouse gas emissions from specified greenhouse gas emission sources in the United States, including petroleum refineries as well as certain onshore oil and natural gas extraction and production facilities.

Several other kinds of cases on greenhouse gases have been heard by the courts in recent years. While courts have generally declined to assign direct liability for climate change to large sources of greenhouse gas emissions, some have required increased scrutiny of such emissions by federal agencies and permitting authorities. There is a continuing risk of claims being filed against companies that have significant greenhouse gas emissions, and new claims for damages and increased government scrutiny will likely continue. Such cases often seek to challenge air emissions permits that greenhouse gas emitters apply for, seek to force emitters to reduce their emissions, or seek damages for alleged climate change impacts to the environment, people, and property. Any court rulings, laws or regulations that restrict or require reduced emissions of greenhouse gases could lead to increased operating and compliance costs, and could have an adverse effect on demand for the oil and natural gas that we produce.

The United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half of the states have already taken measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas "cap and trade" programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal. Recently, the Congressional Budget Office provided Congress with a study on the potential effects on the United States economy of a tax on greenhouse gas emissions. While "carbon tax" legislation has been introduced in the Senate, the prospects for passage of such legislation are highly uncertain at this time.

On June 25, 2013, President Obama outlined plans to address climate change through a variety of executive actions, including reduction of methane emissions from oil and gas production and processing operations as well as pipelines and coal mines (the "Climate Plan"). The President's Climate Plan, along with recent regulatory initiatives and ongoing litigation filed by states and environmental groups, signal a new focus on methane emissions, which could pose substantial regulatory risk to our operations. In March 2014, President Obama released a strategy to reduce methane emissions, which directed the EPA to consider additional regulations to reduce methane emissions from the oil and gas sector. On January 14, 2015, the Obama Administration announced additional steps to reduce methane emissions from the oil and gas sector by 40 to 45 percent by 2025. These actions include a commitment from the EPA to issue new source performance standards for methane emissions from the oil and gas sector. The EPA plans to propose the rule in 2015 and finalize the standards in 2016. The focus on legislating methane also could eventually result in:

•requirements for methane emission reductions from existing oil and gas equipment;

•increased scrutiny for sources emitting high levels of methane, including during permitting processes;

•analysis, regulation and reduction of methane emissions as a requirement for project approval; and

•actions taken by one agency for a specific industry establishing precedents for other agencies and industry sectors.

In relation to the Climate Plan, both assumed Global Warming Potential ("GWP") and assumed social costs associated with methane and other greenhouse gas emissions have been finalized, including a 20% increase in the GWP of methane. Changes to these measurement tools could adversely impact permitting requirements, application of agencies' existing regulations for source categories with high methane emissions, and determinations of whether a source qualifies for regulation under the CAA.

Finally, it should be noted that some scientists have predicted that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. Some scientists refute these predictions. However, President Obama's Climate Plan emphasizes preparation for such events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from flooding or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such events. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. Federal regulations or policy changes regarding climate change preparation requirements could also impact our costs and planning requirements.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which was signed into law on July 21, 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. On October 18, 2011, the Commodities Futures Trading Commission (the "CFTC") approved regulations to set position limits for certain futures and option contracts in the major energy markets, which were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. On November 5, 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The comment period on these new rules has been reopened multiple times since comments were first due in early January 2014, and as these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

Under CFTC final rules promulgated under the Dodd-Frank Act, we believe our derivatives activity will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement. The Dodd-Frank Act may also require us to comply with margin requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. Therefore, the Dodd-Frank Act and the rules promulgated thereunder could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties.

If we reduce our use of derivatives as a result of the Dodd-Frank Act and related regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and related regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Our ability to sell crude oil, natural gas and NGLs, and/or receive market prices for our production, may be adversely affected by constraints on gathering systems, processing facilities, pipelines and other transportation systems owned or operated by others or by other interruptions.

The marketability of our crude oil, natural gas, and NGL production depends in part on the availability, proximity, and capacity of gathering systems, processing facilities, pipelines, and other transportation systems owned or operated by third parties. Any significant interruption in service from, damage to, or lack of available capacity in these systems and facilities can result in the shutting-in of producing wells, the delay or discontinuance of development plans for our properties, or lower price realizations. Although we have some contractual control over the processing and transportation of our operated production, material changes in these business relationships could materially affect our operations. Federal and state regulation of crude oil, natural gas, and NGL production 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, process, and transport crude oil, natural gas, and NGLs.

In particular, if drilling in the Eagle Ford shale and Bakken/Three Forks resource plays continue to be successful, the amount of crude oil, natural gas, and NGLs being produced by us and others could exceed the capacity of, and result in strains on, the various gathering and transportation systems, pipelines, processing facilities, and other infrastructure available in these areas. It will be necessary for additional infrastructure, pipelines, gathering and transportation systems and processing facilities to be expanded, built or developed to accommodate anticipated production from these areas. Because of the current commodity price environment, certain processing, pipeline, and other gathering or transportation projects that might be, or are being, considered for these areas may not be developed timely or at all due to lack of financing or other constraints. Capital and other constraints could also limit our ability to build or access intrastate gathering and transportation systems necessary to transport our production to interstate pipelines or other points of sale or delivery. In such event, we might have to delay or discontinue development activities or shut in our wells to wait for sufficient infrastructure development or capacity expansion and/or sell production at significantly lower prices, which would adversely affect our results of operations and cash flows. In addition, the operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations, which require obtaining and maintaining numerous permits, approvals and certifications from various federal, state, and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations.

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

New technologies may cause our current exploration and drilling methods to become obsolete.
The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies we currently use or implement in the future may become obsolete. We cannot be certain we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

We implemented a new ERP system beginning January 1, 2015. We may experience unforeseen difficulties or delays related to implementation of the new system.

We implemented a new ERP system beginning January 1, 2015. We rigorously planned and tested the implementation of this system prior to its implementation; however, if we encounter unforeseen difficulties in the use of this system, we may experience delays in financial reporting, weaknesses in internal controls, or unanticipated expenses.
Our business could be negatively impacted by security threats, including cybersecurity threats, terrorism, armed conflict, and other disruptions.
As a crude oil, natural gas, and NGLs producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.
Cybersecurity attacks in particular are evolving and include but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for crude oil, natural gas, and NGLs, all of which could adversely affect the markets for our operations. Energy assets might be specific targets of terrorist attacks. These developments have subjected our operations to increased risk and, depending on their occurrence and ultimate magnitude, could have a material adverse effect on our business.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly, which may result in losses for investors.
From January 1, 2014, to February 18, 2015, the low and high intraday sales price per share of our common stock as reported by the New York Stock Exchange ranged from a low of $29.41 per share in December 2014 to a high of $90.38 per share in September 2014. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in crude oil, natural gas, or NGL prices;
- variations in drilling, recompletion, and operating activity;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- future sales of our common stock; and
- changes in the national and global economic outlook.

We may not meet the expectations of our stockholders and/or of securities analysts at some time in the future, and our stock price could decline as a result.
Our certificate of incorporation and by-laws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment, which could adversely affect the price of our common stock.
Delaware corporate law and our certificate of incorporation and by-laws contain provisions that may have the effect of delaying or preventing a change of control of us or our management. These provisions, among other things, provide for non-cumulative voting in the election of members of the Board of Directors and impose procedural requirements on stockholders who wish to make nominations for the election of directors or propose other actions at stockholder meetings. These provisions, alone or in combination with each other, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price investors are willing to pay in the future for shares of our common stock.
Shares eligible for future sale may cause the market price of our common stock to drop significantly, even if our business is doing well.
The potential for sales of substantial amounts of our common stock in the public market may have a materially adverse effect on our stock price. As of February 18, 2015, 67,407,214 shares of our common stock were freely tradable without substantial restriction or the requirement of future registration under the Securities Act. In addition, restricted stock units ("RSUs") providing for the issuance of up to a total of 512,987 shares of our common stock and 744,253 performance share units ("PSUs") were outstanding. The PSUs represent the right to receive, upon settlement of the PSUs after the completion of a three-year performance period, a number of shares of our common stock that may be from zero to two times the number of PSUs granted, depending on the extent to which the underlying performance criteria have been achieved and the extent to which the PSUs have vested. As of February 18, 2015, there were 67,463,060 shares of our common stock outstanding.

We may not always pay dividends on our common stock.
Payment of future dividends remains at the discretion of our Board of Directors, and will continue to depend on our earnings, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to a covenant in our credit facility limiting our annual cash dividends to no more than $50.0 million, and to covenants in the indentures for our Senior Notes that limit our ability to pay dividends beyond a certain amount. Our Board of Directors may determine in the future to reduce the current semi-annual dividend rate of $0.05 per share, or discontinue the payment of dividends altogether.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the filing date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

These disclosures are not applicable to us.

PART II

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

Market Information. Our common stock is currently traded on the New York Stock Exchange under the ticker symbol "SM." The following table presents the range of high and low intraday sales prices per share for the indicated quarterly periods in 2014 and 2013, as reported by the New York Stock Exchange:

Quarter Ended	High	Low
December 31, 2014	$79.89	$29.41
September 30, 2014	$90.38	$74.57
June 30, 2014	$85.39	$71.00
March 31, 2014	$90.22	$69.03
December 31, 2013	$94.00	$76.72
September 30, 2013	$77.70	$60.22
June 30, 2013	$65.55	$55.30
March 31, 2013	$62.26	$52.67

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2009, and ending on December 31, 2014, with the cumulative total returns of the Dow Jones U.S. Exploration and Production Index, and the Standard & Poor's 500 Stock Index.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURNS

The preceding information under the caption Performance Graph shall be deemed to be furnished, but not filed with the SEC.

Holders. As of February 18, 2015, the number of record holders of our common stock was 78. Based upon inquiry, management believes that the number of beneficial owners of our common stock is approximately 25,100.

Dividends. We have paid cash dividends to our stockholders every year since 1940. Annual dividends of $0.05 per share were paid in each of the years 1998 through 2004. Annual dividends of $0.10 per share were paid in 2005 through 2014. We expect our practice of paying dividends on our common stock to continue, although the payment of future dividends will continue to depend on our earnings, cash flow, capital requirements, financial condition, and other factors, including the discretion of our Board of Directors. In addition, the payment of dividends is subject to covenants in our credit facility that limit our annual dividend payment to no more than $50.0 million per year. We are also subject to certain covenants under our Senior Notes that restrict certain payments, including dividends; provided, however, the first $6.5 million of dividends paid each year are not restricted by this covenant. Based on our current performance, we do not anticipate that these covenants will restrict future annual dividend payments of $0.10 per share of common stock. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $6.7 million for each year ended December 31, 2014, and December 31, 2013.

Restricted Shares. We have no restricted shares outstanding as of December 31, 2014, aside from Rule 144 restrictions on shares held by insiders and shares issued to members of the Board of Directors under our Equity Incentive Compensation Plan (“Equity Plan”).

Purchases of Equity Securities by the Issuer and Affiliated Purchasers. The following table provides information about purchases by the Company and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the indicated quarters and year ended December 31, 2014, of shares of the Company’s common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

ISSUER PURCHASES OF EQUITY SECURITIES

	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program(2)
January 1, 2014 - March 31, 2014	—	$—	—	3,072,184
April 1, 2014 - June 30, 2014	866	$73.59	—	3,072,184
July 1, 2014 - September 30, 2014	124,942	$84.14	—	3,072,184
October 1, 2014 - October 31, 2014	668	$71.78	—	3,072,184
November 1, 2014 - November 30, 2014	—	$—	—	3,072,184
December 1, 2014 - December 31, 2014	—	$—	—	3,072,184
Total October 1, 2014 - December 31, 2014	668	$71.78	—	3,072,184
Total	126,476	$84.00	—	3,072,184

(1) All shares purchased in 2014 were purchased by us to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying RSUs and PSUs delivered under the terms of grants under the Equity Plan.

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, subject to the approval of our Board of Directors, we may repurchase up to 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes and compliance with securities laws. Stock repurchases may be funded with

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existing cash balances, internal cash flow, or borrowings under our credit facility. The stock repurchase program may be suspended or discontinued at any time. Please refer to Dividends above for a description of our dividend limitations.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected supplemental financial and operating data as of the dates and periods indicated. The financial data for each of the five years presented were derived from our consolidated financial statements. The following data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of this report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this report.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(in millions, except per share data)				
Total operating revenues	$2,522.3	$2,293.4	$1,505.1	$1,603.3	$1,092.8
Net income (loss)	$666.1	$170.9	$(54.2)	$215.4	$196.8
Net income (loss) per share:					
Basic	$9.91	$2.57	$(0.83)	$3.38	$3.13
Diluted	$9.79	$2.51	$(0.83)	$3.19	$3.04
Total assets at year-end	$6,516.7	$4,705.2	$4,199.5	$3,799.0	$2,744.3
Long-term debt:					
Revolving credit facility	$166.0	$—	$340.0	$—	$48.0
3.50% Senior Convertible Notes, net of debt discount	$—	$—	$—	$285.1	$275.7
Senior Notes	$2,200.0	$1,600.0	$1,100.0	$700.0	$—
Cash dividends declared and paid per common share	$0.10	$0.10	$0.10	$0.10	$0.10

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Supplemental Selected Financial and Operations Data

	For the Years Ended December 31,				
	2014	2013	2012	2011	2010
Balance Sheet Data (in millions)					
Total working capital (deficit)	$(39.6)	$8.4	$(201.0)	$(42.6)	$(227.4)
Total stockholders' equity	$2,286.7	$1,606.8	$1,414.5	$1,462.9	$1,218.5
Weighted-average common shares outstanding (in thousands)					
Basic	67,230	66,615	65,138	63,755	62,969
Diluted	68,044	67,998	65,138	67,564	64,689
Reserves					
Oil (MMBbl)	169.7	126.6	92.2	71.7	57.4
Gas (Bcf)	1,466.5	1,189.3	833.4	664.0	640.0
NGLs (MMBbl)	133.5	103.9	62.3	27.5	—
MMBOE	547.7	428.7	293.4	209.9	164.1
Production and Operations (in millions)					
Oil, gas, and NGL production revenue	$2,481.5	$2,199.6	$1,473.9	$1,332.4	$836.3
Oil, gas, and NGL production expense	$715.9	$597.0	$391.9	$290.1	$195.1
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$767.5	$822.9	$727.9	$511.1	$336.1
General and administrative	$167.1	$149.6	$119.8	$118.5	$106.7
Production Volumes					
Oil (MMBbl)	16.7	13.9	10.4	8.1	6.4
Gas (Bcf)	152.9	149.3	120.0	100.3	71.9
NGLs (MMBbl)	13.0	9.5	6.1	3.5	—
MMBOE	55.1	48.3	36.5	28.3	18.3
Realized price					
Oil (per Bbl)	$80.97	$91.19	$85.45	$88.23	$72.65
Gas (per Mcf)	$4.58	$3.93	$2.98	$4.32	$5.21
NGLs (per Bbl)	$33.34	$35.95	$37.61	$53.32	$—
Adjusted price (net of derivative settlements)					
Oil (per Bbl)	$82.68	$89.92	$83.52	$78.89	$66.85
Gas (per Mcf)	$4.40	$4.14	$3.48	$4.80	$6.05
NGLs (per Bbl)	$34.18	$36.66	$38.90	$47.90	$—
Expense per BOE					
Lease operating expenses	$4.74	$4.82	$4.93	$5.30	$6.63
Transportation costs	$6.11	$5.34	$3.81	$3.05	$1.15
Production taxes	$2.13	$2.19	$2.00	$1.90	$2.86
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$13.92	$17.02	$19.95	$18.07	$18.33
General and administrative	$3.03	$3.09	$3.28	$4.19	$5.82
Statement of Cash Flow Data (in millions)					
Provided by operating activities	$1,456.6	$1,338.5	$922.0	$760.5	$497.1
Used in investing activities	$(2,478.7)	$(1,192.9)	$(1,457.3)	$(1,264.9)	$(361.6)

Provided by (used in) financing activities	$740.0	$130.7	$422.1	$618.5	$(141.1)

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Note: Beginning in 2011, we changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Rapid production growth from our NGL-rich assets associated with plant product sales contracts necessitated a change in our reporting of production volumes. Our 2010 NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the amounts.

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

This discussion includes forward-looking statements. Please refer to Cautionary Information about Forward-Looking Statements in Part I, Items 1 and 2 of this report for important information about these types of statements.

Overview of the Company

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. We have leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays that are the focus of our development programs. We also have smaller delineation and exploration programs in the Powder River Basin, the Permian Basin, and in east Texas. We have built a portfolio of onshore properties primarily through early entry into existing and emerging resource plays. This portfolio is comprised of properties with established production and reserves, prospective drilling opportunities, and unconventional resource prospects. We believe our strategy provides for stable and predictable production and reserves growth.

Our strategic objective is to build our ownership and operatorship of North American oil, gas, and NGL producing assets that have high operating margins and significant opportunities for additional economic investment. We pursue opportunities through both acquisitions and exploration, and seek to maximize the value of our assets through industry leading technology application and outstanding operational execution. We are returns focused and maintain a simple, strong balance sheet through a conservative approach to leverage.

In 2014, we had the following financial and operational results:

- At year-end 2014, we had estimated proved reserves of 547.7 MMBOE, of which 55 percent were liquids (oil and NGLs) and 52 percent were characterized as proved developed. We added 143.9 MMBOE through our drilling program, the majority of which related to our activity in the Eagle Ford shale in south Texas and the Bakken/Three Forks program in North Dakota, and acquired 21.9 MMBOE near our existing Gooseneck area in Divide County, North Dakota and in the Powder River Basin in Wyoming. We had upward engineering revisions of 10.4 MMBOE primarily related to improved performance and lower operating expenses in our operated Eagle Ford assets. We divested of 2.1 MMBOE of proved reserves in the Montana portion of the Williston Basin. Our proved reserve life increased to 9.9 years in 2014 compared to 8.9 years in 2013. Please refer to Reserves included in Part I, Items 1 and 2 of this report for additional discussion.
- The PV-10 of our estimated proved reserves was $7.6 billion as of December 31, 2014, compared with $5.5 billion as of December 31, 2013. The after tax amount, represented by the standardized measure calculation, was $5.7 billion as of December 31, 2014, compared with $4.0 billion as of December 31, 2013. The standardized measure calculation is presented in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report. A reconciliation between PV-10 and the standardized measure of discounted future net cash flows is shown under Reserves in Part I, Items 1 and 2 of this report.
- We had record annual production in 2014. Our average daily production in 2014 was 45.6 MBbls of oil, 419.0 MMcf of gas, and 35.6 MBbls of NGLs, for an average daily equivalent production rate of 151.1 MBOE, compared with 132.4 MBOE in 2013, an increase of 14 percent year-over-year. Please refer to the caption Production Results below for additional discussion.

- We recorded net income of $666.1 million, or $9.79 per diluted share, for the year ended December 31, 2014. This compares with net income of $170.9 million, or $2.51 per diluted share, for the year ended December 31, 2013. This increase in net income in 2014 is driven largely by higher production, an increase in the fair value of commodity derivative contracts, and an increase in oil, gas, and NGL production revenue. Please refer to the caption Comparison of Financial Results and Trends Between 2014 and 2013 below for additional discussion regarding the components of net income.
- We had record cash flow provided by operating activities of $1.5 billion for the year ended December 31, 2014, compared with $1.3 billion for the year ended December 31, 2013, which was an increase of nine percent year-over-year. Please refer to Analysis of cash flow changes between 2014 and 2013 below for additional discussion.
- Costs incurred for oil and gas property acquisitions and exploration and development activities for the year ended December 31, 2014, totaled $2.7 billion. The majority of our drilling and completion costs incurred during this period were in our Eagle Ford shale and Bakken/Three Forks programs. We acquired approximately $561.6 million of proved and unproved properties in our Gooseneck area and in the Powder River Basin during 2014. Total costs incurred for the same period in 2013 totaled $1.7 billion. Please refer to the caption Costs Incurred in Oil and Gas Producing Activities below for additional discussion.
- Adjusted EBITDAX, a non-GAAP financial measure, for the year ended December 31, 2014, was $1.6 billion, compared with $1.5 billion for the same period in 2013. Please refer to the caption Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our GAAP net income (loss) and net cash provided by operating activities to adjusted EBITDAX.

Reserve Replacement, Finding and Development Costs, and Growth

An exploration and production company depletes part of its asset base with each unit of oil, gas, or NGL it produces. Our future growth will depend on our ability to economically add reserves in excess of production. The information used to calculate reserve replacement and finding and development cost metrics is included in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report with the terms defined in the Glossary of Oil and Gas Terms in Part I, Items 1 and 2 of this report.

The following table provides various reserve replacement and finding and development cost metrics for the year ended December 31, 2014:

	Reserve Replacement Percentage		Finding and Development Cost per BOE (1)	
	Excluding Divestitures	Including Divestitures	Excluding Divestitures	Including Divestitures
Drilling, excluding revisions	261 %	257 %	$ 14.39	$ 14.60
Drilling, including revisions	280 %	276 %	$ 13.41	$ 13.60
Drilling and acquisitions, excluding revisions	301 %	297 %	$ 14.14	$ 14.32
Drilling and acquisitions, including revisions	320 %	316 %	$ 13.30	$ 13.46
Reserve acquisitions	40 %	36 %	$ 12.49	$ 13.83
All-in	320 %	316 %	$ 15.39	$ 15.58

(1) Please refer to Note 12 - Acquisition and Development Agreement in Part II, Item 8 for a discussion of the arrangement under which we were carried on 90 percent of certain drilling and completion costs for a portion of 2014. The remaining carry was utilized during the second quarter of 2014.

The following table provides average reserve replacement and finding and development cost metrics for the three-year period ended December 31, 2014:

	Reserve Replacement Percentage				Finding and Development Cost per BOE (1)	
	Excluding Divestitures		Including Divestitures		Excluding Divestitures	Including Divestitures
Drilling, excluding revisions	350	%	333	%	$10.53	$11.06
Drilling, including revisions	341	%	325	%	$10.80	$11.35
Drilling and acquisitions, excluding revisions	366	%	350	%	$10.65	$11.16
Drilling and acquisitions, including revisions	358	%	341	%	$10.91	$11.44
Reserve acquisitions	17	%	N/M		$13.16	N/M
All-in	358	%	341	%	$12.22	$12.81

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N/M - Percentage or amount, as applicable, is not meaningful.

(1) Please refer to Note 12 - Acquisition and Development Agreement in Part II, Item 8 for a discussion of the arrangement under which we were carried on 90 percent of certain drilling and completion costs in 2012, 2013, and for a portion of 2014.

Growing net asset value per share is an important factor in growing our stock price over the long term. We believe annual reserve replacement percentages and finding and development costs are important analytical measures and are widely used by investors and industry peers in evaluating and comparing the performance of oil and gas companies. While single-year measurements are meaningful, we believe aberrations, causing both positive and negative results, will occur over the short term.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. We sell the majority of our gas under contracts using first-of-the-month index pricing, which means gas produced in a given month is sold at the first-of-the-month price regardless of the spot price on the day the gas is produced. For assets where high BTU gas is sold at the wellhead, we also receive additional value for the higher energy content contained in the gas stream. Our NGL production is generally sold using contracts paying us a monthly average of the posted OPIS daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil is sold using contracts paying us various industry posted prices, adjusted for basis differentials. We are paid the average of the daily settlement price for the respective posted prices for the period in which the product is sold, adjusted for quality, transportation, American Petroleum Institute (“API”) gravity, and location differentials. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effects of derivative settlements, unless otherwise indicated.

The following table summarizes commodity price data, as well as the effects of derivative settlements as further discussed under the caption Derivative Activity below, for the years ended December 31, 2014, 2013, and 2012:

	For the Years Ended December 31,		
	2014	2013	2012
Crude Oil (per Bbl):			
Average NYMEX price	$93.03	$97.99	$94.10
Realized price, before the effects of derivative settlements	$80.97	$91.19	$85.45
Effects of derivative settlements	$1.71	$(1.27)	$(1.93)
Natural Gas:			
Average NYMEX price (per MMBtu)	$4.35	$3.73	$2.75
Realized price, before the effects of derivative settlements (per Mcf)	$4.58	$3.93	$2.98
Effects of derivative settlements (per Mcf)	$(0.18)	$0.21	$0.50
NGLs (per Bbl):			
Average OPIS price	$38.93	$40.44	$44.91
Realized price, before the effects of derivative settlements	$33.34	$35.95	$37.61
Effects of derivative settlements	$0.84	$0.71	$1.29

Note: Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents an industry standard composite barrel and does not necessarily represent our actual product mix for NGL production. Actual prices received for NGLs produced reflect our actual product mix.

While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil will continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East. The relative strength of the U.S. dollar compared to other currencies also could affect the price of oil. Lower forecasted levels of global economic growth combined with excess global supply have weighed on oil prices in recent months. This was exacerbated by the decision of the Organization of Petroleum Exporting Countries ("OPEC") not to cut production in November of 2014. The supply of NGLs in the United States has continued to grow as a result of the number of industry participants targeting projects that produce these products in recent years, negatively impacting prices as demand is not as strong. The prices of several NGL products generally correlate to the price of oil and accordingly prices for these products have fallen in recent months and are likely to continue following that market. Gas prices have been under downward pressure for the past several years due to high levels of gas in storage. Longer term, we anticipate natural gas prices will trade in a range higher than current price levels. Changes to existing laws and regulations pertaining to the ability to export oil, gas, and NGLs also have the potential to impact the prices for these commodities.

The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of February 18, 2015, and December 31, 2014:

	As of February 18, 2015	As of December 31, 2014
NYMEX WTI oil (per Bbl)	$57.14	$56.57
NYMEX Henry Hub gas (per MMBtu)	$3.05	$3.06
OPIS NGLs (per Bbl)	$23.80	$20.95

Derivative Activity

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The amount of our production covered by derivatives is driven by the amount of debt on our balance sheet and the level of capital commitments and long-term obligations we have in place. With our current derivative contracts, we believe we have established a base cash flow stream for our future operations and have partially reduced our exposure to volatility in commodity prices in the near term. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil and gas prices while also setting a price floor for a portion of our production. Please refer to Note 10 - Derivative Financial Instruments in Part II, Item 8 of this report for additional information regarding our oil, gas, and NGL derivatives.

The Dodd-Frank Act included provisions requiring over-the-counter derivative transactions to be cleared through clearinghouses and traded on exchanges. On July 10, 2012, the Commodity Futures Trading Commission ("CFTC") and the SEC adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms that determine what types of transactions will be subject to regulation under the Dodd-Frank Act swap rules. The issuance of these final rules also triggers compliance dates for a number of other final Dodd-Frank Act rules, including new rules proposed by the CFTC governing margin requirements for uncleared swaps entered into by non-bank swap entities, and new rules proposed by U.S. banking regulators regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect on our business of these new rules and any additional regulations is currently uncertain. Under CFTC rules we believe our derivative activity will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk entered into by entities predominantly engaged in non-financial activity from the mandatory swap clearing requirement. However, we are not certain whether the provisions of the final rules and regulations will exempt us from the requirements to post margin in connection with commodity price risk management activities. Final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

2014 Highlights

Operational Activities. The primary focus of our operated drilling activity this year was oil and NGL-rich gas projects, with the majority of our 2014 capital budget being deployed to the development of our Eagle Ford shale and Bakken/Three Forks programs.

In our operated Eagle Ford shale program in south Texas, we operated between four and five drilling rigs supported by two frac spreads during 2014. In 2014, our development program shifted to utilizing longer laterals and completions with higher sand loadings. Early results from these enhanced completion techniques suggest significantly improved well performance.

In our non-operated Eagle Ford shale program, the operator ran nine to 10 drilling rigs in the first half of 2014, but dropped to seven rigs in the third quarter. During the second quarter of 2014, the remainder of our carry under our Acquisition and Development Agreement with Mitsui was expended. At that time, we began accruing and funding our full share of drilling and completion costs for this program.

In our Bakken/Three Forks program, we operated three drilling rigs for most of 2014 and added two rigs during the fourth quarter. We focused on infill drilling of our Raven/Bear Den and Gooseneck properties in the North Dakota portion of the Williston Basin. We are monitoring the results of various tests, including drilling and completion optimizations, down-spacing of both our operated and non-operated properties, and we are testing the Bakken interval on our Gooseneck acreage. During 2014, we completed proved and unproved property acquisitions that added approximately 74,000 net acres in our Gooseneck area for a total of $410.1 million.

In our Permian program, we operated two drilling rigs during 2014 focused on horizontal testing and development of the Wolfcamp B interval in our Sweetie Peck property in Upton County, Texas. In our Buffalo prospect in Gaines and Dawson Counties, Texas, we are testing various target intervals, including the Wolfcamp B, Wolfcamp D, and lower Spraberry.

In our Powder River Basin program in Wyoming, we accelerated our delineation activity and expanded our acreage position by approximately 38,000 net acres through multiple acquisitions during 2014. We increased our rig count throughout 2014, exiting the year operating four drilling rigs.

We have an ongoing exploration program to acquire leasehold and test concepts in new plays. In 2014, we continued to evaluate our exploration area in east Texas. We completed the construction of a gathering system in this area at the end of 2014 to allow for longer-term production tests on wells we have drilled and completed.

Production Results. The table below provides a regional breakdown of our production for 2014:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total (1)
Production:					
Oil (MMBbl)	7.1	7.4	2.0	0.1	16.7
Gas (Bcf)	121.6	7.0	4.5	19.8	152.9
NGLs (MMBbl)	12.8	0.1	—	0.1	13.0
Equivalent (MMBOE) (1)	40.2	8.7	2.8	3.5	55.1
Avg. Daily Equivalents (MBOE/d)	110.1	23.9	7.6	9.5	151.1
Relative percentage	73 %	16 %	5 %	6 %	100 %

(1) Totals may not sum or recalculate due to rounding.

We had record production in 2014, which was primarily driven by the continued development of our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Comparison of Financial Results and Trends between 2014 and 2013 below for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Year Ended December 31, 2014 (in millions)
Development costs	$ 1,782.3
Exploration costs	288.3
Acquisitions	
Proved properties	272.9
Unproved properties	368.2
Total, including asset retirement obligation [(1)]	$ 2,711.7

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(1) Please refer to the section Costs Incurred in Oil and Gas Producing Activities in Supplemental Oil and Gas Information in Part II, Item 8 of this report for additional discussion on the costs included in this table.

The majority of our drilling and completion costs incurred during 2014 were in our Eagle Ford shale and Bakken/Three Forks programs. During 2014, we incurred $561.6 million to acquire proved and unproved properties in our Gooseneck area in North Dakota and in the Powder River Basin in Wyoming. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part II, Item 8 of this report for additional discussion.

Divestiture Activity. During the second quarter of 2014, we divested certain non-strategic assets in the Williston Basin located in our Rocky Mountain region. Total cash proceeds received at closing (referred throughout this report as “divestiture proceeds”) were $50.1 million and the final gain on this divestiture was $26.9 million. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part II, Item 8 of this report for additional discussion.

Impairment of Proved and Unproved Properties. We recorded impairment of proved properties expense of $84.5 million and abandonment and impairment of unproved properties expense of $75.6 million for the year ended December 31, 2014. This was a result of the significant decline in commodity prices in late 2014 and recognition of the outcomes of exploration and delineation wells in certain prospects in our South Texas & Gulf Coast and Permian regions.

2022 Notes. During 2014, we issued $600.0 million in aggregate principal amount of 6.125% Senior Notes. The notes were issued at par and mature on November 15, 2022. We received net proceeds of $590.0 million from this issuance, which we used to repay outstanding borrowings under our credit facility and for general corporate purposes. Please refer to Note 5 - Long-term Debt in Part II, Item 8 of this report for additional discussion.

Revolving Credit Facility. In the fourth quarter of 2014, the borrowing base under our credit facility was increased by our lenders to $2.4 billion from $2.2 billion. Additionally, in December 2014 we entered into a Second Amendment to the Fifth Amended and Restated Credit Agreement with our lenders, which resulted in an extension of the maturity date to December 10, 2019, and an increase in current aggregate lender commitments to $1.5 billion. Please refer to Overview of Liquidity and Capital Resources below for additional discussion of our credit facility.

Marketing of Properties. Subsequent to December 31, 2014, we announced our plan to exit the Mid-Continent region and began marketing our assets in the Arkoma Basin of Oklahoma and in the Arklatex area of east Texas and northern Louisiana.

Outlook for 2015

We view 2015 as a year of transition as the broader oil and gas industry adjusts to lower oil prices. Exploration and production companies are reducing drilling and completion activity, which we expect to result in service companies lowering the price for their services. Our plan for 2015 is to scale back activity over the course of the year while preserving the value of our assets and protecting the strength of our balance sheet. Our goal is to be well positioned entering 2016 in what we expect will be a stronger commodity price and lower service cost environment, while having the strength and flexibility to adapt should industry conditions worsen.

Our capital program for 2015 will be approximately $1.2 billion, of which $1.0 billion will be invested in drilling and completion activities. We expect to focus 85 percent of our drilling and completion capital on our core development programs in the Eagle Ford shale and the Bakken/Three Forks formations.

In our operated Eagle Ford shale program, we expect to invest approximately $470 million in drilling and completion activities in 2015. Our plan is to operate four drilling rigs for the majority of the year and to complete wells in a manner that allows us to take advantage of cost reductions currently being realized and expected to continue throughout 2015 and into 2016. We expect we will continue to test the potential of the upper Eagle Ford interval throughout the year.

In our outside-operated Eagle Ford shale program, we expect to invest approximately $135 million for drilling and completion activities in 2015. Our expectation is that the operator will slow the pace of development in 2015. As our carry with Mitsui was fully utilized in 2014, we will be responsible for funding our share of the costs for this program in 2015.

We plan to invest $255 million in our Bakken/Three Forks program in 2015 for drilling and completion activities, approximately 75 percent of which will be on operated properties. We expect to reduce operated drilling activity over the course of the year from a five rig program at the beginning of the year to a two rig program by year-end. We plan to focus more of our activity in our Gooseneck area in Divide County, North Dakota in 2015 to develop and delineate acreage that we added in 2014.

Given current industry conditions, we are scaling back activity in our delineation and exploration programs in 2015. We expect our activity in the Powder River Basin, the Permian Basin, and east Texas will be reduced, and we will focus on preserving those acreage positions.

We currently expect our 2015 capital program to be funded by cash flows from operations and proceeds from planned divestitures, supplemented by borrowings under our credit facility. Please refer to Overview of Liquidity and Capital Resources below for additional discussion.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information for the quarter ended December 31, 2014, and the immediately preceding three quarters. A detailed discussion follows.

	For the Three Months Ended			
	December 31, 2014	September 30, 2014	June 30, 2014	March 31, 2014
	(in millions, except for production data)			
Production (MMBOE)	16.2	13.1	13.4	12.5
Oil, gas, and NGL production revenue	$586.6	$617.2	$654.7	$623.1
Lease operating expense	$75.3	$66.5	$62.8	$57.0
Transportation costs	$93.4	$81.5	$83.0	$79.2
Production taxes	$27.5	$30.4	$31.8	$27.5
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$219.3	$183.3	$187.8	$177.2
Exploration	$49.7	$34.6	$24.3	$21.3
General and administrative	$52.2	$41.7	$38.1	$35.1
Net income	$331.7	$208.9	$59.8	$65.6

Note: Quarterly amounts may not calculate to annual amounts due to rounding.

Selected Performance Metrics:

	For the Three Months Ended			
	December 31, 2014	September 30, 2014	June 30, 2014	March 31, 2014
Average net daily production equivalent (MBOE per day)	175.8	142.5	147.0	138.6
Lease operating expense (per BOE)	$4.66	$5.07	$4.69	$4.58
Transportation costs (per BOE)	$5.77	$6.22	$6.20	$6.35
Production taxes as a percent of oil, gas, and NGL production revenue	4.7 %	4.9 %	4.9 %	4.4 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$13.56	$13.97	$14.03	$14.21
General and administrative (per BOE)	$3.23	$3.18	$2.85	$2.81

Note: Amounts may not recalculate due to rounding.

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A year-to-year overview of selected production and financial information, including trends:

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2014	2013	2012	2014/2013	2013/2012	2014/2013	2013/2012
Net production volumes [1]							
Oil (MMBbl)	16.7	13.9	10.4	2.7	3.6	19 %	34 %
Gas (Bcf)	152.9	149.3	120.0	3.6	29.3	2 %	24 %
NGLs (MMBbl)	13.0	9.5	6.1	3.5	3.4	37 %	55 %
Equivalent (MMBOE) [2]	55.1	48.3	36.5	6.8	11.8	14 %	32 %
Average net daily production [1]							
Oil (MBbl per day)	45.6	38.2	28.3	7.4	9.9	19 %	35 %
Gas (MMcf per day)	419.0	409.2	328.0	9.8	81.2	2 %	25 %
NGLs (MBbl per day)	35.6	26.0	16.7	9.6	9.3	37 %	56 %
Equivalent (MBOE per day) [2]	151.1	132.4	99.7	18.6	32.7	14 %	33 %
Oil, gas, and NGL production revenue (in millions)							
Oil production revenue	$1,348.3	$1,271.5	$886.2	$76.8	$385.3	6 %	43 %
Gas production revenue	699.8	586.3	357.7	113.5	228.6	19 %	64 %
NGL production revenue	433.4	341.8	230.0	91.6	111.8	27 %	49 %
Total	$2,481.5	$2,199.6	$1,473.9	$281.9	$725.7	13 %	49 %
Oil, gas, and NGL production expense (in millions)							
Lease operating expense	$261.6	$233.0	$180.1	$28.6	$52.9	12 %	29 %
Transportation costs	337.1	258.2	138.9	78.9	119.3	31 %	86 %
Production taxes	117.2	105.8	72.9	11.4	32.9	11 %	45 %
Total	$715.9	$597.0	$391.9	$118.9	$205.1	20 %	52 %
Realized price							
Oil (per Bbl)	$80.97	$91.19	$85.45	$(10.22)	$5.74	(11)%	7 %
Gas (per Mcf)	$4.58	$3.93	$2.98	$0.65	$0.95	17 %	32 %
NGLs (per Bbl)	$33.34	$35.95	$37.61	$(2.61)	$(1.66)	(7)%	(4)%
Per BOE [2]	$45.01	$45.50	$40.39	$(0.49)	$5.11	(1)%	13 %
Per BOE data [2]							
Production costs:							
Lease operating expense	$4.74	$4.82	$4.93	$(0.08)	$(0.11)	(2)%	(2)%
Transportation costs	$6.11	$5.34	$3.81	$0.77	$1.53	14 %	40 %
Production taxes	$2.13	$2.19	$2.00	$(0.06)	$0.19	(3)%	10 %
General and administrative	$3.03	$3.09	$3.28	$(0.06)	$(0.19)	(2)%	(6)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$13.92	$17.02	$19.95	$(3.10)	$(2.93)	(18)%	(15)%
Derivative settlement gain [3]	$0.22	$0.42	$1.32	$(0.20)	$(0.90)	(48)%	(68)%
Earnings per share information							
Basic net income (loss) per common share	$9.91	$2.57	$(0.83)	$7.34	$3.40	286 %	410 %
Diluted net income (loss) per common share	$9.79	$2.51	$(0.83)	$7.28	$3.34	290 %	402 %
	67,230	66,615	65,138	615	1,477	1 %	2 %

Basic weighted-average common shares outstanding (in thousands)							
Diluted weighted-average common shares outstanding (in thousands)	68,044	67,998	65,138	46	2,860	— %	4 %

(1) Amounts and percentage changes may not recalculate due to rounding.
(2) 2012 equivalent volumes and per-unit metrics have been conformed to current year presentation on a BOE basis rather than an MCFE basis.
(3) We discontinued hedge accounting on January 1, 2011. As a result, fair values at December 31, 2010, were frozen in accumulated other comprehensive loss ("AOCL") and were reclassified into earnings as the original derivative transactions settled, the last of which settled in the third quarter of 2013. For the years ended December 31, 2013, and 2012, derivative settlements are included within the other operating revenues and derivative gain line items in the accompanying statements of operations. All derivative settlements for the year ended December 31, 2014, are included within the derivative gain line item only.

We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average daily production for the year ended December 31, 2014, increased 14 percent compared to the same period in 2013, driven by continued development of our Eagle Ford shale assets. Please refer to Comparison of Financial Results and Trends between 2014 and 2013 below for additional discussion on changes in our production mix in 2014.

Changes in production volumes, revenues, and costs reflect the highly volatile nature of our industry. Our realized price on a per BOE basis for the year ended December 31, 2014, decreased slightly compared to the same period in 2013. Our derivative contracts had a favorable impact on our average realized price, after the effects of derivative settlements, in the last half of 2014 in light of the significant decline in commodity prices.

Lease operating expense ("LOE") on a per BOE basis for the year ended December 31, 2014, decreased two percent compared to the same period in 2013. Overall, LOE increased; however, production increased at a faster rate, resulting in reduced LOE on a per BOE basis. We experience volatility in our LOE as a result of seasonality in workover expense and the impact that industry activity has on service provider costs. For 2015, we expect a decrease in service provider costs in response to the weak commodity price environment. We anticipate an increase in production in 2015 based on our forecasted drilling plan. Both of these projected trends are expected to drive our LOE on a per BOE basis down in 2015.

Transportation costs on a per BOE basis for the year ended December 31, 2014, increased 14 percent compared to the same period in 2013. Our Eagle Ford shale program has meaningfully higher transportation expense per unit of production compared to our other regions. Ongoing development of the Eagle Ford shale program has resulted in production from these assets becoming a larger portion of our total production, thereby increasing company-wide transportation expense per BOE over time. The run-rate of our per unit transportation cost in the Eagle Ford shale program increased in 2014 due to incremental compression charges and increased variable fuel costs associated with higher natural gas prices. Additionally, our transportation arrangements have shifted over the years to contracts that have more favorable terms for product prices but also include higher transportation fees. We expect this upward trend in transportation costs on a per BOE basis to continue in 2015.

Production taxes on a per BOE basis for the year ended December 31, 2014, decreased three percent compared to the same period in 2013. We generally expect absolute production tax expense to trend with oil, gas, and NGL production revenue. Product mix, the location of production, and incentives to encourage oil and gas development can all impact or change the amount of production tax we recognize.

General and administrative expense on a per BOE basis for the year ended December 31, 2014, decreased two percent compared to the same period in 2013, as production increased at a faster rate than our general and administrative expense. A portion of our general and administrative expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. A portion of our short-term incentive compensation correlates with net cash flows and therefore is subject to variability. In 2015, we expect general and administrative expense on a per BOE basis will decrease, as we anticipate production will continue to increase at a faster rate than our increase in absolute general and administrative expense.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense, for the year ended December 31, 2014, decreased 18 percent, on a per BOE basis, compared to the same period in 2013. Our DD&A rate can fluctuate as a result of impairments, planned and closed divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Our DD&A rate has decreased as assets with lower finding and development costs have become a larger portion of our total production mix. Our finding and development costs have benefited from a general decrease in well costs and an increase in recoveries per well, as well as from our outside-operated Eagle Ford shale program, where, for the last several years and throughout the first half of 2014, we added reserves with minimal associated costs due to our carry with Mitsui under our Acquisition and Development Agreement. This carry was exhausted during the second quarter of 2014. We expect our DD&A rate to increase in future periods as we begin to record our full share of costs in our outside-operated Eagle Ford shale program, which will increase our depletable asset base. Please refer to Note 12 - Acquisition and Development Agreement in Part II, Item 8 of this report for additional discussion on the Mitsui transaction.

Please refer to Comparison of Financial Results and Trends between 2014 and 2013 for additional discussion on oil, gas, and NGL production expense, DD&A expense, and general and administrative expense.

Please refer to the section Earnings per Share in Note 1 - Summary of Significant Accounting Policies in Part II, Item 8 of this report for additional discussion on the types of shares included in our basic and diluted net income (loss) per common share calculations. We recorded a net loss for the year ended December 31, 2012. Consequently, our in-the-money stock options, unvested RSUs, and contingent PSUs were anti-dilutive for the year ended December 31, 2012, resulting in an increase in the diluted weighted-average common shares outstanding for the year ended December 31, 2013, when compared to 2012.

Comparison of Financial Results and Trends between 2014 and 2013

Oil, gas, and NGL production. The following table presents the regional changes in our production and oil, gas, and NGL production revenues and production costs between the years ended December 31, 2014, and 2013:

	Average Net Daily Production Added (Lost)	Oil, Gas & NGL Revenue Added (Lost)	Production Costs Increase (Decrease)
	(MBOE/d)	(in millions)	(in millions)
South Texas & Gulf Coast	25.5	$359.1	$104.3
Rocky Mountain	3.6	40.6	31.0
Permian	1.0	7.2	(0.5)
Mid-Continent	(11.5)	(125.0)	(15.9)
Total	18.6	$281.9	$118.9

The significant production growth in our Eagle Ford shale program far exceeded the production decrease in our Mid-Continent region, which resulted from the divestiture of our assets in the Anadarko Basin in December 2013.

A 14 percent increase in production on an equivalent basis combined with a one percent decrease in realized price per BOE resulted in a 13 percent increase in revenue between the two periods. Based on our planned drilling and completion activity, we expect production volumes to increase in 2015. We expect our realized price, before the effects of derivative settlements, to trend with commodity prices.

Gain (loss) on divestiture activity. We recorded a net gain on divestiture activity of $646,000 for the year ended December 31, 2014, compared with a net gain of $28.0 million in 2013. The net gain on divestiture activity for the year ended December 31, 2014, is due to a gain realized on the sale of non-strategic properties in the Williston Basin in our Rocky Mountain region during the second quarter of 2014 of $26.9 million, which was mostly offset by write downs recorded on assets classified as held for sale in the second and third quarters of 2014. The net gain on divestiture activity for the year ended December 31, 2013, is largely due to gains recorded on the divestiture of certain assets in our Mid-Continent and Rocky Mountain regions slightly offset by a loss recorded on the divestiture of non-strategic assets in our Permian region. We will continue to evaluate our portfolio to determine whether there are non-strategic properties we could divest. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part II, Item 8 of this report for additional discussion.

Marketed gas system revenue and expense. Marketed gas system revenue decreased to $24.9 million for the year ended December 31, 2014, compared with $60.0 million for the comparable period of 2013. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased to $24.5 million for the year ended December 31, 2014, from $57.6 million for the comparable period of 2013. The decrease occurred primarily as a result of the divestiture of our assets in the Anadarko Basin in December 2013, which reduced marketed gas volumes and the overall significance of marketed gas system revenues and expenses. We expect marketed gas revenue and expense to correlate with changes in production and our realized gas price throughout 2015. Subsequent to December 31, 2014, we announced our plan to exit the Mid-Continent region and sell our Arkoma Basin and Arklatex assets. If we successfully divest these assets, our marketed gas volumes will be eliminated.

Other operating revenues. Other operating revenues increased to $15.2 million for the year ended December 31, 2014, compared with $5.8 million for the comparable period of 2013. We recorded a $10.7 million gain in the second quarter of 2014 related to our settlement with Endeavour Operating Corporation (“Endeavour”), in which we, our working interest partners, and Endeavour agreed to mutually release all claims and dismiss certain litigation in exchange for certain cash payments and other consideration.

Oil, gas, and NGL production expense. Total production costs increased $118.9 million, or 20 percent, to $715.9 million for the year ended December 31, 2014, compared with $597.0 million in 2013, primarily due to a 14 percent increase in production volumes on a per BOE basis, as well as an overall increase in transportation costs in our South Texas & Gulf Coast region. Please refer to the caption A year-to-year overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense decreased seven percent to $767.5 million in 2014 compared with $822.9 million in 2013. Please refer to our caption A year-to-year overview of selected production and financial information, including trends above for discussion of DD&A expense on a per BOE basis.

Exploration. The components of exploration expense are summarized as follows:

	For the Years Ended December 31,	
	2014	2013
Summary of Exploration Expense	(in millions)	
Geological and geophysical expenses	$11.4	$4.3
Exploratory dry hole	44.4	5.8
Overhead and other expenses	74.1	64.0
Total	$129.9	$74.1

Exploration expense for 2014 increased 75 percent compared with the same period in 2013 mainly due to expensing three exploratory dry holes in certain prospects in our South Texas & Gulf Coast region in 2014. An exploratory project resulting in non-commercial quantities of oil, gas, or NGLs is deemed an exploratory dry hole and impacts the amount of exploration expense we record. We have an active exploration program, which can result in periodic dry hole expense. During the first quarter of 2014, we performed a seismic study in our Powder River Basin program, which resulted in increased geological and geophysical (“G&G”) expenses year over year. We have also experienced an overall increase in exploration overhead.

Impairment of proved properties. We recorded impairment of proved properties expense of $84.5 million for the year ended December 31, 2014. The impairments recorded in 2014 were a result of the significant decline in commodity prices in late 2014 and recognition of the outcomes of exploration and delineation wells in certain prospects in our South Texas & Gulf Coast and Permian regions. We recorded impairment of proved properties expense of $172.6 million for the comparable period in 2013 as a result of negative engineering revisions on our Mississippian limestone assets in our Permian region at the end of the year, the commencement of a plugging and abandonment program of dry gas assets in the Olmos interval in our South Texas & Gulf Coast region, and our decision to no longer pursue the development of certain under-performing assets during the year. Future crude oil, natural gas, and NGL price declines, downward engineering revisions, or unsuccessful exploration efforts may result in additional proved property impairments.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $75.6 million for the year ended December 31, 2014, related to acreage we no longer intended to develop as a result of exploration and delineation activities and changes to our drilling plans in light of the recent decline in commodity prices. We recorded $46.1 million of abandonment and impairment of unproved properties expense for the comparable period in 2013, the majority of which related to acreage we no longer intended to develop in our Permian region. We expect our abandonment and impairment of unproved properties expense to fluctuate with the timing of lease expirations, unsuccessful exploration activities, and changes in drilling plans if commodity prices remain low.

General and administrative. General and administrative expense increased to $167.1 million for the year ended December 31, 2014, compared with $149.6 million for the same period in 2013. The increase is due to an increase in employee headcount during 2014, which resulted in increased base compensation, benefits, and general corporate office expenses. Please refer to our caption A year-to-year overview of selected production and financial information, including trends above for discussion of general and administrative costs on a per BOE basis.

Change in Net Profits Plan liability. This non-cash expense (benefit) generally relates to the change in the estimated value of the associated liability between the reporting periods. For 2014, we recorded a non-cash benefit of $29.8 million compared to a non-cash benefit of $21.8 million in 2013. The increase in the benefit between these two periods is mostly due to the decrease in commodity strip pricing as of December 31, 2014, as compared to December 31, 2013. The change in our liability is subject to estimation and may change from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, and production costs. We generally expect the change in our Net Profits Plan liability to correlate with fluctuations in commodity prices.

Derivative gain. We recognized a derivative gain of $583.3 million for the year ended December 31, 2014, consisting of a $12.6 million gain on settlements and a $570.7 million increase in the fair value of commodity derivative contracts driven by the significant decline in oil and gas commodity strip pricing in the fourth quarter of 2014. This compares to a net derivative gain of $3.1 million for the same period in 2013, which consists of a $22.1 million gain on settlements and a $19.0 million decrease in the fair value of commodity derivative contracts during the period. Please refer to Note 10 - Derivative Financial Instruments in Part II, Item 8 of this report for additional discussion.

Other operating expenses. Other operating expenses were $4.7 million in 2014 compared with $30.1 million in 2013. In 2013, other operating expenses included $23.1 million of expenses related to an agreed clarification concerning royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage.
Income tax (expense) benefit. We recorded income tax expense of $398.6 million for 2014 compared to income tax expense of $107.7 million for 2013, resulting in effective tax rates of 37.4 percent and 38.6 percent, respectively. The increase in tax expense for the year ended December 31, 2014, generally trends with the increase in net income. The net decrease in tax rate is partially attributable to our 2013 Anadarko Basin divestiture which caused a decrease in the composition of our blended state tax rate for future years offset by an increase in our valuation allowance on state net operating losses in 2014. However, state cash taxes are lower as a result of a decrease in estimated Texas margin tax. Please refer to Note 4 - Income Taxes in Part II, Item 8 of this report for additional discussion. State apportionment factor changes in 2015 and the likelihood we will file amended returns to claim additional research and development ("R&D") credits are expected to result in a lower effective tax rate in 2015.

Comparison of Financial Results and Trends between 2013 and 2012
Oil, gas and NGL production. The following table presents the regional changes in our production and oil, gas, and NGL production revenues and production costs between the years ended December 31, 2013 and 2012:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas & NGL Revenue Added (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	33.4	$515.5	$159.2
Rocky Mountain	3.4	136.6	28.7
Permian	1.4	51.6	19.4
Mid-Continent	(5.5)	22.0	(2.2)
Total	32.7	$725.7	$205.1

The largest regional production increase in 2013 occurred in our South Texas & Gulf Coast region as a result of drilling activity in our Eagle Ford shale program. The increase in oil and gas prices caused an increase in oil, gas, and NGL production revenue in our Mid-Continent region between the years ended December 31, 2013, and 2012, despite a decrease in production volumes attributable to base decline.
A 32 percent increase in production on an equivalent basis combined with a 13 percent increase in realized price per BOE resulted in a 49 percent increase in revenue between the two periods.
Gain (loss) on divestiture activity. We recorded a net gain on divestiture activity of $28.0 million for the year ended December 31, 2013, compared with a net loss of $27.0 million for the comparable period of 2012. The net gain on divestiture activity for the year ended December 31, 2013, was largely due to gains recorded on the divestiture of certain assets in our Mid-Continent and Rocky Mountain regions slightly offset by a loss recorded on the divestiture of non-strategic assets in our Permian region. The net loss for the year ended December 31, 2012, was due to an unsuccessful property sale effort and the corresponding write-down of those assets held for sale to their fair value. This loss was partially offset by a net gain on completed divestitures. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part II, Item 8 of this report for additional discussion.
Marketed gas system revenue and expense. Marketed gas system revenue increased to $60.0 million for the year ended December 31, 2013, compared with $52.8 million for the comparable period of 2012, as a result of an increase in gas prices. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased to $57.6 million for the year ended December 31, 2013, from $47.6 million for the comparable period of

2012. The decrease in our net margin was due to an increase in gathering fees paid to third parties, which went into effect in the second half of 2012.
Oil, gas, and NGL production expense. Total production costs increased $205.1 million, or 52 percent, to $597.0 million for the year ended December 31, 2013, compared with $391.9 million in 2012, primarily due to a 32 percent increase in production volumes on a per BOE basis, as well as an overall increase in transportation costs in our South Texas & Gulf Coast region.
Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased 13 percent to $822.9 million in 2013, compared with $727.9 million in 2012, as a result of the continued development of our Eagle Ford and Bakken/Three Forks assets and the associated growth in our production, partially offset by the sale of our Anadarko Basin properties that were classified as held for sale at the beginning of the third quarter of 2013.
Exploration. The components of exploration expense are summarized as follows:

	For the Years Ended December 31,	
	2013	2012
Summary of Exploration Expense	(in millions)	
Geological and geophysical expenses	$4.3	$13.6
Exploratory dry hole	5.8	20.9
Overhead and other expenses	64.0	55.7
Total	$74.1	$90.2

Exploration expense for 2013 decreased 18 percent compared with the same period in 2012 as a result of decreased G&G due to a large seismic study conducted in the first quarter of 2012 and fewer exploratory dry holes expensed in 2013, partially offset by an increase in exploration overhead in 2013 mainly due to an increase in performance-based compensation.
Impairment of proved properties. We recorded impairment of proved properties expense of $172.6 million for the year ended December 31, 2013. The impairments in 2013 were a result of negative engineering revisions on Mississippian limestone assets in our Permian region at the end of the year, the commencement of a plugging and abandonment program of dry gas assets in the Olmos interval in our South Texas & Gulf Coast region, and our decision to no longer pursue the development of certain under-performing assets during the year. We recorded impairment of proved properties expense of $208.9 million for the comparable period in 2012 related to write-downs of our Wolfberry assets in our Permian region due to downward engineering revisions, as well as write-downs of our Haynesville shale assets due to low natural gas prices.
Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $46.1 million for the year ended December 31, 2013, the majority of which related to acreage we no longer intended to develop in our Permian region. We recorded $16.3 million of abandonment and impairment of unproved properties expense for the comparable period in 2012, the majority of which related to acreage we no longer intended to develop in our Rocky Mountain and Mid-Continent regions.
General and administrative. General and administrative expense increased to $149.6 million for the year ended December 31, 2013, compared with $119.8 million for the same period in 2012. The increase was due to an increase in performance-based compensation that reflects exceeding our performance metrics, as well as an increase in employee headcount during 2013, which resulted in increased base compensation, benefits, and general corporate office expenses. These were slightly offset by an increase in COPAS overhead reimbursement as a result of an increase in operated well count.

Change in Net Profits Plan liability. For 2013, we recorded a non-cash benefit of $21.8 million compared to a non-cash benefit of $28.9 million in 2012. Please refer to Comparison of Financial Results and Trends between 2014 and 2013 above for additional discussion on the assumptions used in estimating the liability.
Derivative gain. We recognized a derivative gain of $3.1 million for the year ended December 31, 2013, which was comprised of a $22.1 million gain on settlements and a $19.0 million decrease in the fair value of commodity derivative contracts during the period. This compares to a gain of $55.6 million for the same period in 2012, which consisted of a $44.3 million gain on settlements and an $11.4 million increase in the fair value of commodity derivative contracts during the period. Please refer to Note 10 - Derivative Financial Instruments in Part II, Item 8 of this report for additional discussion.
Other operating expenses. Other operating expenses were $30.1 million in 2013 compared with $7.0 million in 2012. In 2013, other operating expenses included $23.1 million of expenses related to an agreed clarification concerning royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage.
Income tax (expense) benefit. We recorded income tax expense of $107.7 million for 2013 compared to income tax benefit of $29.3 million for 2012, resulting in effective tax rates of 38.6 percent and 35.0 percent, respectively. The 2013 rate increase resulted primarily from the Anadarko Basin divestiture that closed at the end of 2013, which caused a shift in anticipated recognition of future state tax benefits from a state with a higher applicable state rate to states with lower applicable rates. A combination of lower enacted state income tax rates during the year and a shift between states of our anticipated future apportioned income caused a decrease in our overall state rate which partially offset the increase. Other factors impacting our effective tax rate between tax years include decreased impact for valuation allowances, a decreased impact in benefit from the R&D credit, and to a much lesser extent, net decreases resulting from the differing effects of percentage depletion and other permanent differences.

Overview of Liquidity and Capital Resources
We believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments in order to provide expected flexibility to reduce activity and capital expenditures in periods of prolonged commodity price decline.
Sources of cash
We currently expect our 2015 capital program to be funded by cash flows from operations and proceeds from planned divestitures, supplemented by borrowings under our credit facility. Although we anticipate that cash flows from these sources will be sufficient to fund our expected 2015 capital program, we may also elect to access the capital markets, depending on prevailing market conditions, as well as divest of additional non-strategic oil and gas properties to provide additional sources of funding. From time to time, we may enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. All of our sources of liquidity can be impacted by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, gas, or NGLs, although we are able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. Historically, decreases in commodity prices have limited our industry's access to capital markets. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. See Credit facility below for a discussion of our most recent borrowing base redetermination.

In the fourth quarter of 2014, we issued $600.0 million in aggregate principal amount of 2022 Notes and amended our credit facility agreement, resulting in an extended maturity date and an increased aggregate lender commitment amount.

In late 2011, we consummated our Acquisition and Development Agreement with Mitsui, pursuant to which Mitsui funded, or carried, 90 percent of certain drilling and completion costs attributable to our remaining interest in our non-operated Eagle Ford shale acreage until $680.0 million was expended on our behalf. Our remaining 10 percent was funded over the carry period with the reimbursement of net costs paid attributable to the transferred interest during the period between the effective date and the closing date. The remaining carry was utilized during the second quarter of 2014, at which point we became responsible for funding our share of drilling and completion costs.

Proposals to reform the Internal Revenue Code ("IRC"), which include eliminating or reducing current tax deductions for intangible drilling costs, depreciation of equipment acquisition costs, the domestic production activities deduction, percentage depletion, and other deductions which reduce our taxable income, continue to circulate. We expect that future legislation modifying or eliminating these deductions would reduce net operating cash flows over time, thereby reducing funding available for our exploration and development capital programs, as well as funding available to our peers in the industry for similar programs. If enacted, these funding reductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit facility

During the fourth quarter of 2014, we and our lenders entered into a Second Amendment to our Fifth Amended and Restated Credit Agreement. As amended, the credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.5 billion, and a maturity date of December 10, 2019. On October 6, 2014, the lending group redetermined the Company's borrowing base under the credit facility and increased it from $2.2 billion to $2.4 billion. The subsequent amendment to the credit facility specified that the borrowing base would not be reduced by the issuance of the 2022 Notes and will remain at $2.4 billion until the next scheduled redetermination date of April 1, 2015. The borrowing base redetermination process under the credit facility considers the value of the Company's proved oil and gas properties, as determined by the lender group. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility. Borrowings under our credit facility are secured by mortgages on at least 75 percent of the value of our proved oil and gas properties. Please refer to Note 5 - Long-term Debt in Part II, Item 8 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of February 18, 2015, December 31, 2014, and December 31, 2013.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to adjusted EBITDAX, as defined by our credit agreement as the ratio of debt to 12-month trailing adjusted EBITDAX, of less than 4.0 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. Please refer to the caption Non-GAAP Financial Measures below. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Operating cash flow and cash received from the divestiture of properties were sufficient in meeting our capital expenditure needs through the first half of 2014. During the third quarter of 2014, we began to draw upon our credit facility, primarily to fund acquisitions of oil and gas properties. Our daily weighted-average credit facility debt balance was approximately $86.6 million and $192.4 million for the years ended December 31, 2014, and 2013, respectively. Our daily weighted-average credit facility balance was lower throughout 2014 as a result of proceeds received from property divestitures in the fourth quarter of 2013. In addition, we used the proceeds from our 2022 Notes to reduce our credit facility balance in the fourth quarter of 2014. Cash flows provided by our operating activities, proceeds received from divestitures of properties, and the amount of our capital expenditures all impact the amount we have borrowed under our credit facility.

Weighted-average interest rates

Our calculated weighted-average interest rates include paid and accrued interest, fees on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, and the non-cash amortization of deferred financing costs. Additionally, our 2012 weighted-average interest rate includes amortization of the debt discount related to our 3.50% Senior Convertible Notes due 2027 (the "3.50% Senior Convertible Notes"). Our calculated weighted-average borrowing rates include paid and accrued interest only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the years ended December 31, 2014, 2013, and 2012.

	For the Years Ended December 31,					
	2014		2013		2012	
Weighted-average interest rate	6.5	%	6.3	%	6.4	%
Weighted-average borrowing rate	5.9	%	5.7	%	5.5	%

Our weighted-average interest rates and weighted average borrowing rates for the years ended December 31, 2014, 2013, and 2012, have been impacted by the timing of Senior Notes issuances in 2014 and prior years, the average balance on our revolving credit facility, and the fees paid on the unused portion of our aggregate commitment.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and general and administrative costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. During 2014, we spent $2.5 billion for exploration and development capital activities and proved and unproved oil and gas property acquisitions. These amounts differ from the cost incurred amounts, which are accrual-based and include asset retirement obligation, G&G, and exploration overhead amounts.

The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of acquisition opportunities, our cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our operated and non-operated development and exploratory activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

As of the filing date of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors reviews this program as part of the allocation of our capital. During 2014, we did not repurchase any shares of our common stock, and we currently do not plan to repurchase any outstanding shares.

During 2014, we paid $6.7 million in dividends to our stockholders, which constitutes a dividend of $0.10 per share. Our intention is to continue to make dividend payments for the foreseeable future, subject to our future earnings, our financial condition, credit facility and other covenants, and other factors which could arise. Payment of future dividends remains at the discretion of our Board of Directors.

The following table presents changes in cash flows between the years ended December 31, 2014, 2013, and 2012, for our operating, investing, and financing activities. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part II, Item 8 of this report.

	For the Years Ended December 31,			Amount of Changes Between		Percent of Change Between	
	2014	2013	2012	2014/2013	2013/2012	2014/2013	2013/2012
	(in millions)						
Net cash provided by operating activities	$1,456.6	$1,338.5	$922.0	$118.1	$416.5	9 %	45 %
Net cash used in investing activities	$(2,478.7)	$(1,192.9)	$(1,457.3)	$(1,285.8)	$264.4	108 %	(18)%
Net cash provided by financing activities	$740.0	$130.7	$422.1	$609.3	$(291.4)	466 %	(69)%

Analysis of cash flow changes between 2014 and 2013

Operating activities. Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, increased $256.0 million, or 14 percent, to $2.0 billion for the year ended December 31, 2014, compared with the same period in 2013. Cash paid for lease operating expenses in 2014 increased $20.6 million from 2013. These increases were driven by a 14 percent increase in production volumes. Cash paid for interest, net of capitalized interest, increased $18.4 million during 2014 compared with the same period in 2013 due to the first interest payment on our 2024 Notes issued in 2013 being made in the first quarter of 2014. Additionally, cash bonuses paid in 2014 for the 2013 performance year were $41.8 million compared to $16.3 million paid in 2013 for the 2012 performance year. These changes are offset by a decrease in other operating working capital in 2014.

Investing activities. Capital expenditures in 2014 increased $421.3 million, or 27 percent, compared with the same period in 2013 due to increased spending in our Eagle Ford shale and Bakken/Three Forks programs. Acquisitions of proved and unproved properties increased $483.0 million as a result of property acquisitions in our Gooseneck area and the Powder River Basin in 2014. Net proceeds from the sale of oil and gas properties in 2014 decreased $381.0 million compared to the same period in 2013 due largely to the sale of our Anadarko Basin assets in the fourth quarter of 2013.

Financing activities. We received $590.0 million of net proceeds from the issuance of our 2022 Notes in 2014, compared with $490.2 million of net proceeds from the issuance of our 2024 Notes in 2013. These proceeds were used to repay outstanding borrowings under our credit facility and for general corporate purposes. We had net borrowings under our credit facility of $166.0 million during the year ended December 31, 2014, compared with net payments of $340.0 million during the same period in 2013.

Analysis of cash flow changes between 2013 and 2012

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $652.6 million, or 43 percent, to $2.2 billion for the year ended December 31, 2013, compared with the same period in 2012. Cash paid for lease operating expenses in 2013 increased $54.5 million from 2012. These increases were driven by a 32 percent increase in production volumes. Cash paid for interest, net of capitalized interest, during 2013 increased $19.4 million compared with the same period in 2012 due to interest paid on our 2023 Notes issued in 2012 in the first and third quarters of 2013, offset partially by interest no longer paid on the 3.50% Senior Convertible Notes that we settled in April 2012.

Investing activities. Net proceeds from the sale of oil and gas properties in 2013 increased $369.5 million compared to the same period in 2012 due largely to the sale of our Anadarko Basin assets in the fourth quarter of 2013. Capital expenditures in 2013, including costs to acquire proved and unproved oil and gas properties, increased $101.5 million, or seven percent, compared with the same period in 2012. This increase is primarily the result of our completed acquisition of proved and unproved properties in our Rocky Mountain region in the second quarter of 2013.

Financing activities. We received $490.2 million of net proceeds from the issuance of our 2024 Notes in 2013, compared with $392.1 million of net proceeds from the issuance of our 2023 Notes in 2012. These proceeds were used to repay outstanding borrowings under our credit facility and for general corporate purposes. We had net payments under our credit facility of $340.0 million during the year ended December 31, 2013, compared with net borrowings of $340.0 million during the same period in 2012. During the second quarter of 2012, we paid $287.5 million to settle our 3.50% Senior Convertible Notes.

Interest Rate Risk

We are exposed to market risk due to the floating interest rate on our revolving credit facility. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months. To the extent that the interest rate is fixed, interest rate changes will affect the credit facility’s fair market value, but will not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value, but will impact future results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes, but can impact their fair market values. As of December 31, 2014, our fixed-rate debt and floating-rate debt outstanding totaled $2.2 billion and $166.0 million, respectively. The carrying amount of our floating-rate debt at December 31, 2014, approximates its fair value. Assuming a constant floating-rate debt level of $166.0 million, the before-tax cash flow impact resulting from a 100 basis point change in our interest rate would be $1.7 million over a 12-month period.

Commodity Price Risk

The prices we receive for our oil, gas, and NGL production directly impact our revenue, overall profitability, access to capital, and future rate of growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. The markets for oil, gas, and NGLs have been volatile, especially in recent months, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on our 2014 production, a 10 percent decrease in our average realized price, before the effects of derivative settlements, would have reduced our oil, gas, and NGL production revenues by $134.8 million, $70.0 million, and $43.3 million, respectively.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. Please refer to Note 10 – Derivative Financial Instruments of Part II, Item 8 of this report for additional information about our oil, gas, and NGL derivative contracts.

The fair values of our commodity derivative contracts are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2014, a 10 percent increase or decrease in the forward curves associated with our oil, gas, and NGL commodity derivative instruments would have changed our net asset positions by approximately $85 million, $78 million, and $2 million, respectively.

Schedule of Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2014, for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$2,366.0	$—	$—	$516.0	$1,850.0
Interest payments (2)	1,051.1	140.7	281.5	269.5	359.4
Delivery commitments (3)	939.4	113.5	227.0	245.4	353.5
Operating leases and contracts (3)	197.1	111.4	39.2	16.4	30.1
Net Profits Plan (4)	28.1	5.9	10.1	8.4	3.7
Asset retirement obligations (5)	152.3	28.4	4.0	7.6	112.3
Other (6)	31.9	6.0	10.5	12.1	3.3
Total	$4,765.9	$405.9	$572.3	$1,075.4	$2,712.3

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(1) Long-term debt consists of our Senior Notes and the outstanding balance under our long-term revolving credit facility, and assumes no principal repayment until the due dates of the instruments. The actual payments under our revolving credit facility may vary significantly.

(2) Interest payments on our Senior Notes are estimated assuming no principal repayment until the due dates of the instruments. Interest payments on our credit facility have been estimated using the rate applicable to the balance on our credit facility as of December 31, 2014, and assume no future borrowing or repayment until the December 10, 2019 due date. The actual interest payments on our Senior Notes and credit facility may vary significantly.

(3) Please refer to Note 6 – Commitments and Contingencies in Part II, Item 8 of this report for additional discussion regarding our operating leases, contracts, and gathering, processing, and transportation through-put commitments.

(4) Amounts shown represent undiscounted forecasted payments for the Net Profits Plan for the next six years. Payments are expected to gradually decrease for the years beyond what are shown in this table and are not included due to these payments being highly variable, as outlined below. The amount recorded on the accompanying consolidated balance sheets reflects all future Net Profits Plan payments and the impact of discounting, and therefore differs from the amounts disclosed in this table. The variability in the amount of payments will be a direct reflection of commodity prices, production rates, capital expenditures, and operating costs in future periods. Predicting the timing and amounts of payments associated with this liability is contingent upon estimates of appropriate discount factors, adjusting for risk and time value, and upon a number of factors we cannot control. Please refer to Note 7 – Compensation Plans and Note 11 - Fair Value Measurements in Part II, Item 8 of this report for additional discussion regarding our Net Profits Plan liability.

(5) Amounts shown represent estimated future undiscounted plugging and abandonment costs. The discounted obligations are recorded as liabilities on our accompanying consolidated balance sheets as of December 31, 2014. The timing and amount of the ultimate settlement of these obligations is unknown and can be impacted by economic factors, a change in development plans, and federal and state regulations. Inactive wells as of December 31, 2014, are shown as an obligation in 2015 due to the substantial uncertainty on the timing of plugging or re-entering these shut-in or temporarily abandoned wells. Please refer to Note 9 – Asset Retirement Obligations in Part II, Item 8 of this report for additional discussion regarding our asset retirement obligations.

(6) The majority of the amount shown relates to the unfunded portion of our estimated pension liability of $29.9 million, for which we have estimated the timing of future payments based on historical annual contribution amounts. We expect to make contributions to our pension plan in 2015 of $5.8 million. Other amounts include the liability

portion of the marked-to-market value of our commodity derivatives based on estimates of the forward curves of the relevant price indices at December 31, 2014, and excludes estimated oil, gas, and NGL commodity derivative receipts.

Off-balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities (“SPEs”), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements. We have not been involved in any unconsolidated SPE transactions in 2014 or 2013.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements in conformity with accounting principles generally accepted in the United States (“GAAP”) requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses, as well as the disclosure of contingent assets and liabilities as of the date of our financial statements. We base our assumptions and estimates on historical experience and various other sources that we believe to be reasonable under the circumstances. Actual results may differ from the estimates we calculate due to changes in circumstances, global economics and politics, and general business conditions. A summary of our significant accounting policies is detailed in Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report. We have outlined below those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Oil and gas reserve quantities. Our estimated proved reserve quantities and future net cash flows are critical to the understanding of the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in our financial statements, including the calculations of depletion and impairment of proved oil and gas properties and the estimate of our Net Profits Plan liability. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10 percent discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves. We engage Ryder Scott, an independent reservoir-evaluation consulting firm, to audit at least 80 percent of our total calculated proved reserve PV-10. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves each year-end. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with GAAP for the impact of additions and dispositions. Changes in depletion or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period the reserve estimates change. Please refer to Supplemental Oil and Gas Information in Part II, Item 8 of this report.

The following table presents information about proved reserve changes from period to period due to items we do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Years Ended December 31,		
	2014	2013	2012
	MMBOE Change	MMBOE Change	MMBOE Change
Revisions resulting from price changes	3.4	0.6	(12.1)
Revisions resulting from performance (1)	7.0	4.4	(15.3)
Total	10.4	5.0	(27.4)

(1) Performance revisions include the removal of proved undeveloped reserves that are no longer in our development plan within five years.

As previously noted, commodity prices are volatile, and estimates of reserves are inherently imprecise. Consequently, we expect to continue experiencing these types of changes. Please refer to additional reserves discussion above under Overview of the Company.

The following table reflects the estimated MMBOE change and percentage change to our total reported reserve volumes from the described hypothetical changes:

	For the Years Ended December 31,					
	2014		2013		2012	
	MMBOE Change	Percentage Change	MMBOE Change	Percentage Change	MMBOE Change	Percentage Change
10% decrease in SEC pricing	(9.6)	(2)%	(9.8)	(2)%	(11.2)	(4)%
10% decrease in proved undeveloped reserves	(26.1)	(5)%	(22.0)	(5)%	(12.7)	(4)%

The table above solely reflects the impact of a 10 percent decrease in SEC pricing or decrease in proved undeveloped reserves and does not include additional impacts to our proved reserves that may result from our internal intent to drill hurdles or changes in future service or equipment costs. Additional reserve information can be found in the reserve table and discussion included in Items 1 and 2 of Part I of this report, and in Supplemental Oil and Gas Information of Part II, Item 8 of this report.

Successful efforts method of accounting. GAAP provides for two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method. Both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities. A more detailed description is included in Note 1 - Summary of Significant Accounting Policies of Part II, Item 8 of this report.

Revenue recognition. Our revenue recognition policy is significant because revenue is a key component of our results of operations and our forward-looking statements contained in our analysis of liquidity and capital resources. We derive our revenue primarily from the sale of produced oil, gas, and NGLs. Revenue is recognized when our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month, we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, NYMEX, local spot market, and OPIS prices, and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A 10 percent change in our year end revenue accrual would have impacted total operating revenues by approximately $18 million in 2014.

Asset retirement obligations. We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells and our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, estimate future inflation rates, and determine what credit-adjusted risk-free discount rate to use. The impact to the accompanying consolidated statements of operations from these estimates is reflected in our depreciation, depletion, and amortization calculations and occurs over the remaining life of our respective oil and gas properties. Please refer to Note 9 – Asset Retirement Obligations in Part II, Item 8 of this report for additional discussion.

Impairment of oil and gas properties. Our proved oil and gas properties are recorded at cost. We evaluate our proved properties for impairment when events or changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our oil and gas properties and compare these undiscounted cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future operating and capital expenditures, and discount rates.

Unproved oil and gas properties are assessed periodically for impairment on a prospect-by-prospect basis based on the remaining lease terms, drilling results, commodity price outlook, and future capital allocations. Unproved oil and gas properties are impaired when we determine that the property will not be developed or the carrying value will not be realized.

Please refer to Impairment of Proved and Unproved Properties in Note 1 - Summary of Significant Accounting Policies in Part II, Item 8 of this report for impairment results.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil, gas and NGL price volatility. The accounting treatment for the change in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is designated as a cash flow hedge. Prior to January 1, 2011, we designated our commodity derivative contracts as cash flow hedges, for which unrealized changes in fair value were recorded to AOCL, to the extent the hedges were effective. As of January 1, 2011, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010. As a result, subsequent to December 31, 2010, we recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, option pricing models, futures prices, volatility, time to maturity, and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Income taxes. We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we use and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement could have an impact on our results of operations. A one percent change in our effective tax rate would have changed our calculated income tax expense by approximately $10.6 million for the year ended December 31, 2014.

Accounting Matters

Please refer to the section entitled Recently Issued Accounting Standards under Note 1 – Summary of Significant Accounting Policies for additional information on the recent adoption of new authoritative accounting guidance in Part II, Item 8 of this report.

Environmental

We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. For additional information about hydraulic fracturing and related environmental matters, see Risk Factors – Risks Related to Our Business – Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other ‘‘greenhouse gases’’ present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In June 2013, President Obama announced a Climate Action Plan designed to further reduce greenhouse gas emissions and prepare the nation for the physical effects that may occur as a result of climate change. The Plan targets methane reductions from the oil and gas sector as part of a comprehensive interagency methane strategy. On January 14, 2015, the Obama Administration announced additional steps to reduce methane emissions from the oil and gas sector by 40 to 45 percent by 2025. These actions include a commitment from the EPA to issue new source performance standards for methane emissions from the oil and gas sector. The EPA plans to propose the rule in 2015 and finalize the standards in 2016. The EPA has not committed to proposing existing source standards for the oil and gas sector. In addition, President Obama directed the EPA to issue stringent carbon standards for new fossil fuel-fired power plants. The EPA proposed new source performance standards in September 2013, which would require carbon capture and sequestration for coal-fired boilers and combined cycle technology for natural gas-fired

boilers. The EPA plans to finalize the new source performance standards in the summer of 2015. In June 2014, the EPA proposed existing source performance standards as stringent state emission “goals.” The proposed standards focus on re-dispatching electricity from coal-fired units to natural gas combined cycle plants and renewables. The EPA plans to finalize the rule in the summer of 2015, with state plans to implement and enforce the standards in 2016.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition, and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods, and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

In terms of opportunities, the regulation of greenhouse gas emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration, and low carbon fuel standards, could benefit us in a variety of ways. For example, although federal regulation and climate change legislation could reduce the overall demand for the oil and natural gas that we produce, the relative demand for natural gas may increase because the burning of natural gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources, such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, natural gas may become a more attractive transportation fuel. Approximately 46 and 51 percent of our production on an BOE basis in 2014 and 2013, respectively, was natural gas. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and natural gas reservoirs, could also benefit us through the potential to obtain greenhouse gas emission allowances or offsets from or government incentives for the sequestration of carbon dioxide.

Non-GAAP Financial Measures

Adjusted EBITDAX represents income (loss) before interest expense, other non-operating income or expense, income taxes, depreciation, depletion, amortization, and accretion, exploration expense, property impairments, non-cash stock compensation expense, derivative gains and losses net of settlements, change in the Net Profits Plan liability, and gains and losses on divestitures. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that is presented because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to a financial covenant under our credit facility based on our debt to adjusted EBITDAX ratio. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or profitability or liquidity measures

prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies.

The following table provides reconciliations of our net income (loss) and net cash provided by operating activities to adjusted EBITDAX for the periods presented:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Net income (loss) (GAAP)	$666,051	$170,935	$(54,249)
Interest expense	98,554	89,711	63,720
Other non-operating (income) expense, net	2,561	(67)	(220)
Income tax expense (benefit)	398,648	107,676	(29,268)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	767,532	822,872	727,877
Exploration [1]	122,577	65,888	81,809
Impairment of proved properties	84,480	172,641	208,923
Abandonment and impairment of unproved properties	75,638	46,105	16,342
Stock-based compensation expense	32,694	32,347	30,185
Derivative gain	(583,264)	(3,080)	(55,630)
Derivative settlement gain [2]	12,615	22,062	44,264
Change in Net Profits Plan liability	(29,849)	(21,842)	(28,904)
(Gain) loss on divestiture activity	(646)	(27,974)	27,018
Adjusted EBITDAX (Non-GAAP)	1,647,591	1,477,274	1,031,867
Interest expense	(98,554)	(89,711)	(63,720)
Other non-operating income (expense), net	(2,561)	67	220
Income tax (expense) benefit	(398,648)	(107,676)	29,268
Exploration [1]	(122,577)	(65,888)	(81,809)
Exploratory dry hole expense	44,427	5,846	20,861
Amortization of debt discount and deferred financing costs	6,146	5,390	6,769
Deferred income taxes	397,780	105,555	(29,638)
Plugging and abandonment	(8,796)	(9,946)	(2,856)
Other, net	1,069	2,775	527
Changes in current assets and liabilities	(9,302)	14,828	10,480
Net cash provided by operating activities (GAAP)	$1,456,575	$1,338,514	$921,969

(1) Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations for the component of stock-based compensation expense recorded to exploration.

(2) Derivative settlement gain is reported in the derivative cash settlements line item on the accompanying statements of cash flows within net cash provided by operating activities with the change in accrued settlements between years being reported in change in accounts receivable and change in accounts payable and accrued expenses line items.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity Price Risk and Interest Rate Risk in Item 7 above, as well as under the section entitled Summary of Oil, Gas, and NGL Derivative Contracts in Place under Note 10 – Derivative Financial Instruments in Part II, Item 8 of this report and is incorporated herein by reference.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of SM Energy Company and subsidiaries

We have audited the accompanying consolidated balance sheets of SM Energy Company and subsidiaries as of December 31, 2014, and 2013, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of SM Energy Company and subsidiaries at December 31, 2014, and 2013, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), SM Energy Company's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 25, 2015, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
February 25, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of SM Energy Company and Subsidiaries
Denver, Colorado

We have audited the accompanying consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows of SM Energy Company and subsidiaries (the "Company") for the year ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of SM Energy Company and subsidiaries for the year ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 21, 2013

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share amounts)

	December 31, 2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	$120	$282,248
Accounts receivable (note 2)	322,630	318,371
Derivative asset	402,668	21,559
Deferred income taxes	—	10,749
Prepaid expenses and other	19,625	14,574
Total current assets	745,043	647,501
Property and equipment (successful efforts method):		
Proved oil and gas properties	7,348,436	5,637,462
Less - accumulated depletion, depreciation, and amortization	(3,233,012)	(2,583,698)
Unproved oil and gas properties	532,498	271,100
Wells in progress	503,734	279,654
Oil and gas properties held for sale, net of accumulated depletion, depreciation and amortization of $22,482 and $7,390, respectively	17,891	19,072
Other property and equipment, net of accumulated depreciation of $37,079 and $28,775, respectively	334,356	236,202
Total property and equipment, net	5,503,903	3,859,792
Noncurrent assets:		
Derivative asset	189,540	30,951
Restricted cash	—	96,713
Other noncurrent assets	78,214	70,208
Total other noncurrent assets	267,754	197,872
Total Assets	$6,516,700	$4,705,165
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 2)	$640,684	$606,751
Derivative liability	—	26,380
Deferred tax liability	142,976	—
Other current liabilities	1,000	6,000
Total current liabilities	784,660	639,131
Noncurrent liabilities:		
Revolving credit facility	166,000	—
Senior Notes (note 5)	2,200,000	1,600,000
Asset retirement obligation	120,867	118,692
Net Profits Plan liability	27,136	56,985
Deferred income taxes	891,681	650,125
Derivative liability	70	4,640
Other noncurrent liabilities	39,631	28,771
Total noncurrent liabilities	3,445,385	2,459,213

Commitments and contingencies (note 6)

Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 67,463,060 and 67,078,853 shares outstanding, respectively; net of treasury shares: 67,463,060 and 67,056,441, respectively	675	671
Additional paid-in capital	283,295	257,720
Treasury stock, at cost: zero and 22,412 shares, respectively	—	(823)
Retained earnings	2,013,997	1,354,669
Accumulated other comprehensive loss	(11,312)	(5,416)
Total stockholders' equity	2,286,655	1,606,821
Total Liabilities and Stockholders' Equity	$6,516,700	$4,705,165

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	For the Years Ended December 31, 2014	2013	2012
Operating revenues:			
Oil, gas, and NGL production revenue	$2,481,544	$2,199,550	$1,473,868
Gain (loss) on divestiture activity	646	27,974	(27,018)
Marketed gas system revenue	24,897	60,039	52,808
Other operating revenues	15,220	5,811	5,444
Total operating revenues and other income	2,522,307	2,293,374	1,505,102
Operating expenses:			
Oil, gas, and NGL production expense	715,878	597,045	391,872
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	767,532	822,872	727,877
Exploration	129,857	74,104	90,248
Impairment of proved properties	84,480	172,641	208,923
Abandonment and impairment of unproved properties	75,638	46,105	16,342
General and administrative	167,103	149,551	119,815
Change in Net Profits Plan liability	(29,849)	(21,842)	(28,904)
Derivative gain	(583,264)	(3,080)	(55,630)
Marketed gas system expense	24,460	57,647	47,583
Other operating expenses	4,658	30,076	6,993
Total operating expenses	1,356,493	1,925,119	1,525,119
Income (loss) from operations	1,165,814	368,255	(20,017)
Non-operating income (expense):			
Other, net	(2,561)	67	220
Interest expense	(98,554)	(89,711)	(63,720)
Income (loss) before income taxes	1,064,699	278,611	(83,517)
Income tax (expense) benefit	(398,648)	(107,676)	29,268
Net income (loss)	$666,051	$170,935	$(54,249)
Basic weighted-average common shares outstanding	67,230	66,615	65,138
Diluted weighted-average common shares outstanding	68,044	67,998	65,138
Basic net income (loss) per common share	$9.91	$2.57	$(0.83)
Diluted net income (loss) per common share	$9.79	$2.51	$(0.83)

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	For the Years Ended December 31,		
	2014	2013	2012
Net income (loss)	$666,051	$170,935	$(54,249)
Other comprehensive income (loss), net of tax:			
Reclassification to earnings [(1)]	—	1,115	(2,264)
Pension liability adjustment [(2)]	(5,896)	2,483	(2,470)
Total other comprehensive income (loss), net of tax	(5,896)	3,598	(4,734)
Total comprehensive income (loss)	$660,155	$174,533	$(58,983)

(1) Reclassification from accumulated other comprehensive loss related to de-designated hedges. Refer to Note 10 - Derivative Financial Instruments for further information.

(2) Refer to Note 1 - Summary of Significant Accounting Policies for detail of the pension amount reclassified to general and administrative expense on the Company’s consolidated statements of operations.

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except share amounts)

	Common Stock		Additional Paid-in	Treasury Stock		Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Shares	Amount	Earnings	Loss	Equity
Balances, January 1, 2012	64,145,482	$641	$216,966	(81,067)	$(1,544)	$1,251,157	$ (4,280)	$1,462,940
Net loss	—	—	—	—	—	(54,249)	—	(54,249)
Other comprehensive loss	—	—	—	—	—	—	(4,734)	(4,734)
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,511)	—	(6,511)
Issuance of common stock under Employee Stock Purchase Plan	66,485	1	2,775	—	—	—	—	2,776
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	929,375	9	(21,631)	—	—	—	—	(21,622)
Issuance of common stock upon stock option exercises	240,368	2	3,038	—	—	—	—	3,040
Conversion of 3.50% Senior Convertible Notes to common stock, including income tax benefit of conversion	864,106	9	2,632	—	—	—	—	2,641
Stock-based compensation expense	—	—	29,862	30,486	323	—	—	30,185
Balances, December 31, 2012	66,245,816	$662	$233,642	(50,581)	$(1,221)	$1,190,397	$ (9,014)	$1,414,466
Net income	—	—	—	—	—	170,935	—	170,935
Other comprehensive income	—	—	—	—	—	—	3,598	3,598
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,663)	—	(6,663)
Issuance of common stock under Employee Stock Purchase Plan	77,427	1	3,671	—	—	—	—	3,672
Issuance of common stock upon vesting	526,852	5	(16,225)	—	—	—	—	(16,220)

of RSUs and settlement of PSUs, net of shares used for tax withholdings								
Issuance of common stock upon stock option exercises	228,758	3	3,183	—	—	—	—	3,186
Stock-based compensation expense	—	—	31,949	28,169	398	—	—	32,347
Other income tax benefit	—	—	1,500	—	—	—	—	1,500
Balances, December 31, 2013	67,078,853	$671	$257,720	(22,412)	$(823)	$1,354,669	$(5,416)	$1,606,821
Net income	—	—	—	—	—	666,051	—	666,051
Other comprehensive income	—	—	—	—	—	—	(5,896)	(5,896)
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,723)	—	(6,723)
Issuance of common stock under Employee Stock Purchase Plan	83,136	1	4,060	—	—	—	—	4,061
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	256,718	3	(10,627)	—	—	—	—	(10,624)
Issuance of common stock upon stock option exercises	39,088	—	816	—	—	—	—	816
Stock-based compensation expense	5,265	—	31,871	22,412	823	—	—	32,694
Other income tax expense	—	—	(545)	—	—	—	—	(545)
Balances, December 31, 2014	67,463,060	$675	$283,295	—	$—	$2,013,997	$(11,312)	$2,286,655

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Years Ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net income (loss)	$666,051	$170,935	$(54,249)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
(Gain) loss on divestiture activity	(646)	(27,974)	27,018
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	767,532	822,872	727,877
Exploratory dry hole expense	44,427	5,846	20,861
Impairment of proved properties	84,480	172,641	208,923
Abandonment and impairment of unproved properties	75,638	46,105	16,342
Stock-based compensation expense	32,694	32,347	30,185
Change in Net Profits Plan liability	(29,849)	(21,842)	(28,904)
Derivative gain	(583,264)	(3,080)	(55,630)
Derivative cash settlements	(28,419)	22,062	44,264
Amortization of debt discount and deferred financing costs	6,146	5,390	6,769
Deferred income taxes	397,780	105,555	(29,638)
Plugging and abandonment	(8,796)	(9,946)	(2,856)
Other, net	1,069	2,775	527
Changes in current assets and liabilities:			
Accounts receivable	24,088	(78,494)	(21,389)
Prepaid expenses and other	(1,822)	98	733
Accounts payable and accrued expenses	9,466	93,224	31,136
Net cash provided by operating activities	1,456,575	1,338,514	921,969
Cash flows from investing activities:			
Net proceeds from sale of oil and gas properties	43,858	424,849	55,375
Capital expenditures	(1,974,798)	(1,553,536)	(1,507,828)
Acquisition of proved and unproved oil and gas properties	(544,553)	(61,603)	(5,773)
Other, net	(3,256)	(2,613)	893
Net cash used in investing activities	(2,478,749)	(1,192,903)	(1,457,333)
Cash flows from financing activities:			
Proceeds from credit facility	1,285,500	1,203,000	1,609,000
Repayment of credit facility	(1,119,500)	(1,543,000)	(1,269,000)
Debt issuance costs related to credit facility	(3,388)	(3,444)	—
Net proceeds from Senior Notes	589,991	490,185	392,138
Repayment of 3.50% Senior Convertible Notes	—	—	(287,500)
Proceeds from sale of common stock	4,877	6,858	5,816
Dividends paid	(6,723)	(6,663)	(6,511)
Net share settlement from issuance of stock awards	(10,624)	(16,220)	(21,622)
Other, net	(87)	(5)	(225)
Net cash provided by financing activities	740,046	130,711	422,096
Net change in cash and cash equivalents	(282,128)	276,322	(113,268)

Cash and cash equivalents at beginning of period	282,248	5,926	119,194
Cash and cash equivalents at end of period	$120	$282,248	$5,926

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

Supplemental schedule of additional cash flow information and non-cash activities:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Cash paid for interest, net of capitalized interest	$89,145	$70,702	$51,328
Net cash paid (refunded) for income taxes	$1,936	$(204)	$(1,389)

As of December 31, 2014, 2013, and 2012, $357.2 million, $217.8 million, and $262.8 million, respectively, of accrued capital expenditures were included in accounts payable and accrued expenses in the Company's consolidated balance sheets. These oil and gas property additions are reflected in cash used in investing activities in the periods during which the payables are settled.

During the second quarter of 2014, the Company exchanged properties in its Rocky Mountain region with a fair value of $6.2 million. During the third quarter of 2013, the Company exchanged properties in its Rocky Mountain region with a fair value of $25.0 million. The cash consideration exchanged at the respective closings for agreed upon adjustments is reflected in the acquisition of proved and unproved oil and gas properties line item in the consolidated statements of cash flows.

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Summary of Significant Accounting Policies
Description of Operations
SM Energy Company is an independent energy company engaged in the acquisition, exploration, development, and production of crude oil and condensate, natural gas, and NGLs in onshore North America.

Basis of Presentation
The accompanying consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries and have been prepared in accordance with GAAP and the instructions to Form 10-K and Regulation S-X. Subsidiaries that the Company does not control are accounted for using the equity or cost methods as appropriate. Equity method investments are included in other noncurrent assets in the accompanying consolidated balance sheets ("accompanying balance sheets"). Intercompany accounts and transactions have been eliminated. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2014, through the filing date of this report.
Certain prior period amounts have been reclassified to conform to the current period presentation on the accompanying financial statements. The Company's refundable income taxes are combined and presented in the prepaid expenses and other financial statement line item within the accompanying balance sheets. The Company's land and materials inventory are combined and presented in the other property and equipment, net of accumulated depreciation financial statement line item within the accompanying balance sheets. Lastly, the asset retirement obligation associated with oil and gas properties held for sale is no longer separately presented and is presented in the asset retirement obligation financial statement line item within the accompanying balance sheets. Within the accompanying consolidated statements of operations ("accompanying statements of operations"), the Company's realized hedge gain (loss) is combined and presented in the other operating revenues financial statement line item. In the accompanying consolidated statements of cash flows ("accompanying statements of cash flows") in cash flows from operating activities, refundable income taxes is now combined and presented with prepaid expenses and other. Additionally, receipts from restricted cash related to any like-kind exchanges under Section 1031 of the Internal Revenue Code are now combined and presented in the other, net financial statement line item within net cash used in investing activities on the accompanying statements of cash flows.
Use of Estimates in the Preparation of Financial Statements
The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of proved oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of proved oil and gas reserve quantities provide the basis for the calculation of depletion, depreciation, and amortization expense, impairment of proved properties, asset retirement obligations, and the Net Profits Plan liability, each of which represents a significant component of the accompanying consolidated financial statements.
Cash and Cash Equivalents
The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Restricted Cash

The Company has no restricted cash at December 31, 2014. The restricted cash balance at December 31, 2013, mainly consisted of cash payments that were contractually restricted to be used solely for development of long-term capital assets pursuant to the Company's Acquisition and Development Agreement with Mitsui and accordingly classified as non-current assets. Please refer to Note 12 - Acquisition and Development Agreement for additional information.

Accounts Receivable

The Company's accounts receivable consist mainly of receivables from oil, gas, and NGL purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, the Company's oil and gas receivables are collected within two months, and the Company has had minimal bad debts.

Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized. As of December 31, 2014 and 2013, the Company had no allowance for doubtful accounts recorded.

Concentration of Credit Risk and Major Customers

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is subject to regular review. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil, natural gas, and NGLs are products with well-established markets and numerous purchasers in the Company's operating regions. During 2014, the Company had one major customer, which accounted for approximately 19 percent of total production revenue, which is discussed in the next paragraph. In 2014, the Company also sold to four entities that are under common ownership. In aggregate, these four entities accounted for approximately 14 percent of total production revenues in 2014, however, none of these entities individually accounted for greater than 10 percent of total production revenue. During 2013, the Company had three major customers, which accounted for approximately 26 percent, 16 percent, and 12 percent, respectively, of total production revenue. During 2012, the Company had two major customers, which accounted for approximately 21 percent and 13 percent, respectively, of total production revenue.

During the third quarter of 2013, the Company entered into various marketing agreements with a joint venture partner, whereby the Company is subject to certain gathering, transportation, and processing through-put commitments for up to 10 years pursuant to each contract. While the Company's joint venture partner is the first purchaser under these contracts, accounting for 19 percent of total production revenue in 2014, the Company also shares with them the risk of non-performance by their counterparty purchasers. Several of the Company's joint venture partner's counterparty purchasers under these contracts are also direct purchasers of products produced by the Company.

The Company's policy is to use the commodity affiliates of the lenders under its credit facility as its derivative counterparties. Additionally, the Company's policy is that the counterparty must have investment grade senior unsecured debt ratings. Each of the Company's nine counterparties currently meet both of these requirements.

The Company has accounts in the following locations with a national bank: Denver, Colorado; Houston, Texas; Midland, Texas; and Billings, Montana. The Company's policy is to invest in highly-rated instruments and to limit the amount of credit exposure at each individual institution.

Oil and Gas Producing Activities

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. G&G costs are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either development or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures within the accompanying statements of cash flows. The costs of development wells are capitalized whether those wells are successful or unsuccessful.

DD&A of capitalized costs related to proved oil and gas properties is calculated on a pool-by-pool basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. As of December 31, 2014, and 2013, the estimated salvage value of the Company's equipment was $50.8 million and $57.5 million, respectively.

Assets Held for Sale

Any properties held for sale as of the balance sheet date have been classified as assets held for sale and are separately presented on the accompanying balance sheets at the lower of net book value or fair value less the cost to sell. For additional discussion on assets held for sale, please refer to Note 3 – Acquisitions, Divestitures, and Assets Held for Sale.

Other Property and Equipment

Other property and equipment such as facilities, office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using either the straight-line method over the estimated useful lives of the assets, which range from three to 30 years, or the unit of output method where appropriate. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Internal-Use Software Development Costs

The Company capitalizes certain software costs incurred during the application development stage. The application development stage generally includes software design, configuration, testing and installation activities. Training and maintenance costs are expensed as incurred, while upgrades and enhancements are capitalized if it is probable that such expenditures will result in additional functionality. Capitalized software costs are depreciated over the estimated useful life of the underlying project on a straight-line basis upon completion of the project. As of December 31, 2014, and 2013, the Company has capitalized approximately $35.0 million and $11.2 million, respectively, related to the ongoing development and implementation of accounting and operational software.

Derivative Financial Instruments

The Company seeks to manage or reduce commodity price risk on production by entering into derivative contracts. The Company seeks to minimize its basis risk and indexes its oil derivative contracts to NYMEX prices, its NGL derivative contracts to OPIS prices, and its gas derivative contracts to various regional index prices associated with pipelines into which the Company's gas production is sold. For additional discussion on derivatives, please see Note 10 – Derivative Financial Instruments.

Net Profits Plan

The Company records the estimated fair value of expected future payments to be made under the Net Profits Plan as a noncurrent liability in the accompanying balance sheets. The underlying assumptions used in the calculation of the estimated liability include estimates of production, proved reserves, recurring and workover lease operating expense, transportation, production and ad valorem tax rates, present value discount factors, pricing assumptions, and overall market conditions. The estimates used in calculating the long-term liability are adjusted from period-to-period based on the most current information attributable to the underlying assumptions. Changes in the estimated liability of future payments associated with the Net Profits Plan are recorded as increases or decreases to expense in the current period as a separate line item in the accompanying statements of operations, as these changes are considered changes in estimates.

The distribution amounts due to participants and payable in each period under the Net Profits Plan as cash compensation related to periodic operations are recognized as compensation expense and are included within general and administrative expense and exploration expense in the accompanying statements of operations. The corresponding current liability is included in accounts payable and accrued expenses in the accompanying balance sheets. This treatment provides for a consistent matching of cash expense with net cash flows from the oil and gas properties in each respective pool of the Net Profits Plan. For additional discussion, please refer to the heading Net Profits Plan in Note 7 – Compensation Plans and Note 11 – Fair Value Measurements.

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. For additional discussion, please refer to Note 9 – Asset Retirement Obligations.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, gas, and NGLs. Revenue is recognized when the Company’s production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses knowledge of its properties and historical performance, NYMEX, OPIS, and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates. The Company uses the sales method of accounting for gas revenue whereby sales revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company’s ownership in the property.

Impairment of Proved and Unproved Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value, which is based on expected future discounted cash flows, when there is an indication that the carrying costs may not be recoverable. Expected future cash flows are calculated on all proved developed reserves and risk adjusted proved undeveloped, probable, and possible reserves using a discount rate and price forecasts that management believes are representative of current market conditions. The prices for oil and gas are forecasted based on NYMEX strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecasted using OPIS pricing, adjusted for basis differentials, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. An impairment is recorded on unproved property when the Company determines that either the property will not be developed or the carrying value is not realizable.

The Company recorded $84.5 million, $172.6 million, and $208.9 million, of proved property impairment expense for the years ended December 31, 2014, 2013, and 2012, respectively. The impairments of proved properties in 2014 were a result of the significant decline in commodity prices in late 2014 and recognition of the outcomes of exploration and delineation wells in certain prospects in the Company’s South Texas & Gulf Coast and Permian regions. The impairments in 2013 resulted from the write-down of certain Mississippian limestone assets in the Company’s Permian region due to negative engineering revisions, write-downs related to Olmos interval, dry gas assets in the South Texas & Gulf Coast region as a result of a plugging and abandonment program, and write-downs of certain underperforming assets due to the Company’s decision to no longer pursue the development of those assets. The impairments in 2012 were a result of the Company’s write-down of Wolfberry assets in its Permian region due to negative engineering revisions and the Company’s Haynesville shale assets as a result of low natural gas prices.

For the years ended December 31, 2014, 2013, and 2012, the Company recorded expense related to the abandonment and impairment of unproved properties of $75.6 million, $46.1 million, and $16.3 million, respectively. The Company’s abandonment and impairment of unproved properties expense in 2014 was due to acreage the Company no longer intended to develop as a result of exploration and delineation activities and the recent decline in commodity prices. The Company’s abandonment and impairment of unproved properties expense in 2013 was mostly related to acreage the Company no longer intended to develop in its Permian region. The Company’s abandonment and impairment of unproved properties expense in 2012 related to acreage that the Company no longer intended to develop in its Rocky Mountain region.

Sales of Proved and Unproved Properties

The partial sale of proved property within an existing field is accounted for as normal retirement and no gain or loss on divestiture activity is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an individual proved property is accounted for as a recovery of cost. A gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of proved properties.

The partial sale of unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to the ultimate recovery of the cost applicable to the interest retained. A gain on divestiture activity is recognized to the extent that the sales price exceeds the carrying amount of the unproved property. A gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of unproved property. For additional discussion, please refer to Note 3 – Acquisitions, Divestitures, and Assets Held for Sale.

Stock-Based Compensation

At December 31, 2014, the Company had stock-based employee compensation plans that included RSUs, PSUs, and restricted stock awards issued to employees and non-employee directors, as more fully described in Note 7 - Compensation Plans. The Company records expense associated with the fair value of stock-based compensation in accordance with authoritative accounting guidance, which is based on the estimated fair value of these awards determined at the time of grant.

Income Taxes

The Company accounts for deferred income taxes whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amounts on the financial statements and the tax basis of assets and liabilities, as measured using current enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recorded or settled, respectively. The Company records deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis.

Earnings per Share

Basic net income (loss) per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income (loss) per common share is calculated by dividing adjusted net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options, unvested RSUs, contingent PSUs, and shares into which the 3.50% Senior Convertible Notes were convertible. When there is a loss from continuing operations, as was the case for the year ended December 31, 2012, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted earnings per share.

PSUs represent the right to receive, upon settlement of the PSUs after the completion of the three-year performance period, a number of shares of the Company’s common stock that may range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to Note 7 – Compensation Plans under the heading Performance Share Units Under the Equity Incentive Compensation Plan.

The Company called for redemption of its 3.50% Senior Convertible Notes on April 2, 2012, after which the majority of the holders of the outstanding 3.50% Senior Convertible Notes elected to convert their notes. The Company issued 864,106 common shares upon conversion, and these shares were included in the calculation of basic weighted-average common shares outstanding for the year ended December 31, 2012, and all subsequent years the shares remain outstanding. Please refer to Note 5 - Long-term Debt for additional discussion. Prior to calling the 3.50% Senior Convertible Notes for redemption, the Company’s notes had a net-share settlement right giving the Company the option to irrevocably elect, by notice to the trustee under the indenture for the notes, to settle the Company’s obligation, in the event that holders of the notes elected to convert all or a portion of their notes, by delivering cash in an amount equal to each $1,000 principal amount of notes surrendered for conversion and, if applicable, at the Company’s option, shares of common stock or cash, or any combination of common stock and cash, for the amount of conversion value in excess of the principal amount. Prior to the settlement of the Company’s 3.50% Senior Convertible Notes, potentially dilutive shares associated with the conversion feature were accounted for using the treasury stock method when shares of the Company’s common stock traded at an average closing price that exceeded the $54.42 conversion price. Shares of the Company’s common stock traded at an average closing price exceeding the conversion price and were included on an adjusted weighted basis for the portion of the year ended December 31, 2012, for which they were outstanding. The Company recorded a loss from continuing operations for the year ended December 31, 2012, and therefore, the shares into which the 3.50% Senior Convertible Notes were convertible were anti-dilutive and excluded from the calculation of diluted earnings per share, as shown in the table below.

The treasury stock method is used to measure the dilutive impact of in-the-money stock options, unvested RSUs, contingent PSUs, and the 3.50% Senior Convertible Notes.

The following table details the weighted-average dilutive and anti-dilutive securities related to stock options, RSUs, PSUs, and the 3.50% Senior Convertible Notes for the years presented:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Dilutive	814	1,383	—
Anti-dilutive	—	—	2,102

The following table sets forth the calculations of basic and diluted earnings per share:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands, except per share amounts)		
Net income (loss)	$666,051	$170,935	$(54,249)
Basic weighted-average common shares outstanding	67,230	66,615	65,138
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	814	1,383	—
Add: dilutive effect of 3.50% Senior Convertible Notes (1)	—	—	—
Diluted weighted-average common shares outstanding	68,044	67,998	65,138
Basic net income (loss) per common share	$9.91	$2.57	$(0.83)
Diluted net income (loss) per common share	$9.79	$2.51	$(0.83)

(1) For the year ended December 31, 2012, the shares into which the 3.50% Senior Convertible Notes were convertible were anti-dilutive and excluded from the calculation of diluted earnings per share.

Comprehensive Income (Loss)

Comprehensive income (loss) is used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of stockholders' equity instead of net income (loss). Comprehensive income (loss) is presented net of income taxes in the accompanying consolidated statements of comprehensive income (loss).

The changes in the balances of components comprising other comprehensive income (loss) are presented in the following table:

	Derivative Adjustments	Pension Liability Adjustments
	(in thousands)	
For the year ended December 31, 2012		
Net actuarial loss		$(4,680)
Reclassification to earnings	$(3,865)	771
Tax benefit	1,601	1,439
Loss, net of tax	$(2,264)	$(2,470)
For the year ended December 31, 2013		
Net actuarial gain		$2,766
Reclassification to earnings	$1,777	1,239
Tax expense	(662)	(1,522)
Income, net of tax	$1,115	$2,483
For the year ended December 31, 2014		
Net actuarial loss		$(10,062)
Reclassification to earnings	$—	706
Tax benefit	—	3,460
Loss, net of tax	$—	$(5,896)

Fair Value of Financial Instruments

The Company’s financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Company’s credit facility approximates its fair value as it bears interest at a floating rate that approximates a current market rate. The Company had $166.0 million of outstanding loans under its credit facility as of December 31, 2014. The Company had no borrowings outstanding under its credit facility as of December 31, 2013. The Company’s Senior Notes are recorded at cost and the respective fair values are disclosed in Note 11 - Fair Value Measurements. The Company has derivative financial instruments that are recorded at fair value. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Industry Segment and Geographic Information

The Company operates in the exploration and production segment of the oil and gas industry and all of the Company’s operations are conducted entirely within the United States. The Company reports as a single industry segment. The Company’s gas marketing function provides mostly internal services and acts as the first purchaser of natural gas and natural gas liquids produced by the Company in certain cases. The Company considers its marketing function as ancillary to its oil and gas producing activities. The amount of income these operations generate from marketing gas produced by third parties is not material to the Company’s results of operations, and segmentation of such activity would not provide a better understanding of the Company’s performance. However, gross revenue and expense related to marketing activities for gas produced by third parties are presented in the marketed gas system revenue and marketed gas system expense line items in the accompanying statements of operations.

Off-Balance Sheet Arrangements

The Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities (“SPE”), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

The Company evaluates its transactions to determine if any variable interest entities exist. If it is determined that SM Energy is the primary beneficiary of a variable interest entity, that entity is consolidated into SM Energy. The Company has not been involved in any unconsolidated SPE transactions in 2014 or 2013.

Recently Issued Accounting Standards

Effective October 1, 2014, the Company early adopted, on a prospective basis, Financial Accounting Standards Board (“FASB”) Accounting Standards Update (“ASU”) No. 2014-08, “Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity.” This ASU changed the criteria for reporting discontinued operations while enhancing disclosures in this area. There was no impact to the Company’s financial statements or disclosures from the early adoption of this standard.

In May 2014, the FASB issued new authoritative accounting guidance related to the recognition of revenue from contracts with customers. This guidance is to be applied using a retrospective method or a modified retrospective method, as outlined in the guidance, and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. Early application is not permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company’s financial statements and disclosures.

In August 2014, the FASB issued new authoritative guidance that requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity’s ability to continue as a going concern within one year after the date that the entity’s financial statements are issued, or within one year after the date the entity’s financial statements are available to be issued, and to provide disclosures when certain criteria are met. This guidance is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company’s financial statements and disclosures but does not believe it will impact the Company's financial statements or disclosures.

In January 2015, the FASB issued new authoritative accounting guidance that simplifies income statement presentation by eliminating extraordinary items from GAAP. This guidance is to be applied either prospectively or retrospectively and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. Early application is permitted provided the guidance is applied from the beginning of the annual year of adoption. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company’s financial statements and disclosures.

In February 2015, the FASB issued new authoritative accounting guidance meant to clarify the consolidation reporting guidance in GAAP. This guidance is to be applied using a retrospective method or a modified retrospective method, as outlined in the guidance, and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company’s financial statements and disclosures.

There are no other accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of December 31, 2014, and through the filing date of this report.

Note 2 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	As of December 31,	
	2014	2013
	(in thousands)	
Accrued oil, gas, and NGL production revenue	$180,250	$228,169
Amounts due from joint interest owners	58,347	37,517
Accrued derivative settlements	39,811	770
State severance tax refunds	24,394	29,213
Other	19,828	22,702
Total accounts receivable	$322,630	$318,371

Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2014	2013
	(in thousands)	
Accrued capital expenditures	$357,156	$217,820
Revenue and severance tax payable	63,779	87,852
Accrued lease operating expense	34,822	29,296
Accrued property taxes	15,059	10,401
Joint owner advances	152	96,636
Accrued compensation	56,279	71,466
Accrued interest	40,786	40,027
Other	72,651	53,253
Total accounts payable and accrued expenses	$640,684	$606,751

Note 3 – Acquisitions, Divestitures, and Assets Held for Sale

2014 Acquisition Activity

- Gooseneck Property Acquisitions. On September 24, 2014, the Company acquired approximately 61,000 net acres of proved and unproved oil and gas properties in its Gooseneck area in North Dakota, along with related equipment, contracts, records, and other assets. Total cash consideration paid by the Company was $325.2 million and the effective date for the acquisition was July 1, 2014.

On October 15, 2014, the Company acquired additional interests in proved and unproved oil and gas properties in its Gooseneck area. Total cash consideration paid by the Company was $84.8 million and the effective date for the acquisition was August 1, 2014.

It was determined that both of these acquisitions met the criteria of a business combination under Accounting Standards Codification ("ASC") Topic 805, Business Combinations. The Company allocated the preliminary adjusted purchase price to the acquired assets and liabilities based on fair value as of the respective acquisition dates, as summarized in the table below. These acquisitions are subject to normal post-closing adjustments, which are expected to be completed in the first half of 2015. Refer to Note 11 – Fair Value Measurements for additional discussion on the valuation techniques used in determining the fair value of acquired properties.

Purchase Price	As of September 24, 2014 (in thousands)	As of October 15, 2014
Cash consideration	$325,230	$84,836
Fair value of assets acquired:		
Proved oil and gas properties	$203,493	$54,360
Unproved oil and gas properties	126,622	29,469
Total fair value of oil and gas properties acquired	330,115	83,829
Working capital	(2,772)	2,625
Asset retirement obligation	(2,113)	(1,618)
Total fair value of net assets acquired	$325,230	$84,836

- Rocky Mountain Acquisitions. In addition to the Gooseneck property acquisitions discussed above, the Company acquired other proved and unproved properties in its Rocky Mountain region during 2014 in multiple transactions for approximately $134.5 million in total cash consideration, plus approximately 7,000 net acres of non-core assets in the Company's Rocky Mountain region. These acquisitions are subject to normal post-closing adjustments, which are expected to be completed in early 2015.

2014 Divestiture Activity

- Rocky Mountain Divestiture. During the second quarter of 2014, the Company divested certain non-core assets in the Montana portion of the Williston Basin. Total divestiture proceeds were $50.1 million and the final gain on this divestiture was $26.9 million.

The Company recorded $27.6 million of write-downs to fair value less estimated costs to sell for assets that were held for sale during the year ended December 31, 2014, which are reflected as a loss on divestiture activity in the accompanying statements of operations, and mostly offset the gain on the Rocky Mountain divestiture discussed above. Please refer to Assets Held for Sale below for further discussion.

2013 Divestiture Activity

- Mid-Continent Divestitures. In December 2013, the Company divested of certain non-strategic assets located in its Mid-Continent region, with the largest transaction being the sale of the Company's Anadarko Basin assets. Total divestiture proceeds were $368.5 million and the net gain on these divestitures was $25.3 million. A portion of one transaction was structured to qualify as a like-kind exchange under Section 1031 of the IRC.

- Rocky Mountain Divestitures. During 2013, the Company divested of certain non-strategic assets located in its Rocky Mountain region. Final divestiture proceeds for these divestitures were $57.1 million and the final net gain was $13.2 million.

- Permian Divestiture. In December 2013, the Company divested of certain non-strategic assets located in its Permian region. Final proceeds for this divestiture were $14.0 million and the final net loss was $7.0 million.

The Company recorded an immaterial write-down to fair value less estimated costs to sell for assets that were held for sale as of December 31, 2013.

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2012 Divestiture Activity

In 2012, the Company divested of various non-strategic properties located in its Rocky Mountain and Mid-Continent regions. Final divestiture proceeds were $57.9 million and the final net gain on these divestitures was $7.4 million.

During 2012, the Company reclassified a portion of the assets previously held for sale to assets held and used, as the assets were no longer being actively marketed. The assets were measured at the lower of the carrying value of the assets before being classified as held for sale, adjusted for any DD&A that would have been recognized had the assets been continuously held and used, or the fair value of the assets at the date they no longer met the criteria as held for sale. As a result of this measurement, the Company recognized $1.7 million of DD&A expense and a $33.9 million loss on unsuccessful sale of properties, which is included in gain (loss) on divestiture activity in the accompanying statements of operations.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less costs to sell. Subsequent changes to the estimated fair value less the costs to sell will impact the measurement of assets held for sale for which fair value less costs to sell is determined to be less than the carrying value of the assets.

As of December 31, 2014, the accompanying balance sheets present $17.9 million of assets held for sale, net of accumulated DD&A expense. There is a corresponding asset retirement obligation liability of $438,000 for assets held for sale included in the asset retirement obligation financial statement line item. Assets held for sale are recorded at the lesser of their respective carrying value or fair value less estimated costs to sell. Certain assets classified as held for sale during 2014 were written down to fair value less estimated costs to sell, which was recorded in the gain (loss) on divestiture activity line item in the accompanying statements of operations.

Subsequent to December 31, 2014, the Company began marketing its assets in the Arkoma Basin of Oklahoma and in the Arklatex area of east Texas and northern Louisiana and expects the assets to be sold during 2015. These assets did not meet the requirements to be classified as held for sale as of December 31, 2014.

The Company determined that neither these planned nor executed asset sales qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Current portion of income tax expense			
Federal	$—	$—	$—
State	868	2,121	370
Deferred portion of income tax expense (benefit)	397,780	105,555	(29,638)
Total income tax expense (benefit)	$398,648	$107,676	$(29,268)
Effective tax rate	37.4%	38.6%	35.0%

The Company reduces its income tax payable to reflect employee stock option exercises. There was no excess income tax benefit associated with stock awards in 2014, 2013, or 2012.

The components of the net deferred income tax liabilities are as follows:

	As of December 31,	
	2014	2013
	(in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$1,029,424	$768,463
Derivative asset	220,437	9,529
Other	4,475	1,245
Total deferred tax liabilities	1,254,336	779,237
Deferred tax assets:		
Federal and state tax net operating loss carryovers	184,447	91,788
Stock compensation	16,763	18,820
Other long-term liabilities	16,301	13,341
Net Profits Plan liability	9,414	20,913
Total deferred tax assets	226,925	144,862
Valuation allowance	(7,246)	(5,001)
Net deferred tax assets	219,679	139,861
Total net deferred tax liabilities	1,034,657	639,376
Less: current deferred income tax liabilities	(152,082)	(172)
Add: current deferred income tax assets	9,106	10,921
Non-current net deferred tax liabilities	$891,681	$650,125
Current federal income tax refundable	$4,734	$4,630
Current state income tax refundable	$—	$—
Current state income tax payable	$25	$1,460

At December 31, 2014, the Company estimated its federal net operating loss carryforward at $626.2 million, which includes unrecognized excess income tax benefits associated with stock awards of $126.7 million. The federal net operating loss carryforward begins to expire in 2031. The Company has estimated state net operating loss carryforwards of $284.8 million that expire between 2015 and 2035 and it has federal R&D credit carryforwards of $3.5 million that expire between 2028 and 2032. The Company's valuation allowance relates to charitable contribution carryforwards, state net operating loss carryforwards, and state tax credits, which the

Company anticipates will expire before they can be utilized. The change in the valuation allowance from 2013 to 2014 primarily reflects a change in the Company's position regarding anticipated utilization of cumulative state net operating losses.

Federal income tax expense differs from the amount that would be provided by applying the statutory United States federal income tax rate to income before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, percentage depletion, R&D credits, and other permanent differences, as follows:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Federal statutory tax expense (benefit)	$372,644	$97,514	$(29,231)
Increase (decrease) in tax resulting from:			
State tax expense (benefit) (net of federal benefit)	21,350	9,400	(992)
Research and development credit	—	—	(970)
Change in valuation allowance	2,245	(314)	1,524
Other	2,409	1,076	401
Income tax expense (benefit)	$398,648	$107,676	$(29,268)

Acquisitions, divestitures, drilling activity, and basis differentials impacting the prices received for oil, gas, and NGLs affect apportionment of taxable income to the states where the Company owns oil and gas properties. As its apportionment factors change, the Company's blended state income tax rate changes. This change, when applied to the Company's total temporary differences, impacts the total state income tax expense (benefit) reported in the current year. Items affecting state apportionment factors are evaluated at the beginning of each year, after completion of the prior year income tax return, and when significant acquisition, divestiture or changes in drilling activity or estimated state revenue occurs during the year.

The Company and its subsidiaries file federal income tax returns and various state income tax returns. With certain exceptions, the Company is no longer subject to United States federal or state income tax examinations by these tax authorities for years before 2007. The Internal Revenue Service ("IRS") initiated an audit in the first quarter of 2012 related to an R&D tax credit claimed by the Company for the 2007 through 2010 tax years. On April 23, 2013, the IRS issued a Notice of Proposed Adjustment disallowing $4.6 million of an R&D tax credit claimed for open tax years during the audit period. During the third quarter ended September 30, 2014, the Company successfully reached an agreement with the IRS Appeals Office ("Appeals") related to the claimed R&D credit and recorded an immaterial adjustment. In the fourth quarter of 2014, Appeals returned the case to the Examination Team for final review. At December 31, 2014, the Company was waiting on final review and evaluating the basis for claiming the R&D credit for the 2012 and 2013 tax years. Subsequent to year-end, the Company concluded its evaluation, and preliminary estimates indicate it may be entitled to claim approximately $2.4 million of additional net R&D credit. The Company anticipates finalizing the amounts and filing amended returns in the first quarter of 2015. The tables above do not include the impact of the estimated amount.

On September 13, 2013, the United States Department of the Treasury and IRS issued final and re-proposed tangible property regulations effective for tax years beginning January 1, 2014. The Company has determined it is materially compliant with the requirements of these regulations as of December 31, 2014.

The Company complies with authoritative accounting guidance regarding uncertain tax provisions. The entire amount of unrecognized tax benefit reported by the Company would affect its effective tax rate if recognized. Interest expense in the accompanying statements of operations includes a negligible amount associated with income taxes. At December 31, 2014, the Company estimates the range of reasonably possible change in 2015 to the table below could be from zero to $1.2 million.

The total amount recorded for unrecognized tax benefits is presented below:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Beginning balance	$2,358	$2,278	$1,961
Additions for tax positions of prior years	140	80	317
Settlements	(916)	—	—
Ending balance	$1,582	$2,358	$2,278

Note 5 – Long-term Debt

Revolving Credit Facility

The Company and its lenders entered into a Second Amendment to the Fifth Amended and Restated Credit Agreement on December 10, 2014. The Company incurred approximately $3.4 million in deferred financing costs associated with the amendment and extension of this credit facility. As amended, the Company's credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.5 billion, and a maturity date of December 10, 2019. The borrowing base is subject to regular semi-annual redeterminations. On October 6, 2014, the lending group redetermined the Company's borrowing base under the credit facility and increased it from $2.2 billion to $2.4 billion. The December 10, 2014 amendment to the credit facility specified that the borrowing base was not reduced by the issuance of the 2022 Notes and will remain at $2.4 billion until the next redetermination date, scheduled for April 1, 2015. The borrowing base redetermination process under the credit facility considers the value of the Company's proved oil and gas properties, as determined by the lender group. Borrowings under the facility are secured by at least 75 percent of the value of the Company's proved oil and gas properties.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to adjusted EBITDAX, as defined by the Company's credit agreement as the ratio of debt to 12-month trailing adjusted EBITDAX, of less than 4.0 and an adjusted current ratio, as defined by the Company's credit agreement, of no less than 1.0. The Company was in compliance with all financial and non-financial covenants under the credit facility as of December 31, 2014, and through the filing date of this report.

Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate plus the applicable margin from the utilization table below, and Alternate Base Rate ("ABR") and swingline loans accrue interest at Prime plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying statements of operations.

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Loans	1.250%	1.500%	1.750%	2.000%	2.250%
ABR Loans or Swingline Loans	0.250%	0.500%	0.750%	1.000%	1.250%
Commitment Fee Rate	0.300%	0.300%	0.350%	0.375%	0.375%

The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under the Company's credit facility as of February 18, 2015, December 31, 2014, and December 31, 2013:

	As of February 18, 2015	As of December 31, 2014	As of December 31, 2013
	(in thousands)		
Credit facility balance	$341,000	$166,000	$—
Letters of credit [1]	$808	$808	$808
Available borrowing capacity	$1,158,192	$1,333,192	$1,299,192

[1] Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis.

Senior Notes

The Senior Notes line on the accompanying balance sheets, as of December 31, 2014, and 2013, consisted of the following:

	As of December 31,	
	2014	2013
	(in thousands)	
2019 Notes	$350,000	$350,000
2021 Notes	350,000	350,000
2022 Notes	600,000	—
2023 Notes	400,000	400,000
2024 Notes	500,000	500,000
Total Senior Notes	$2,200,000	$1,600,000

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt, and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the Senior Notes. The Company is subject to certain covenants under the indenture governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by the restricted payment covenant. The Company was in compliance with all covenants under its Senior Notes as of December 31, 2014, and through the filing date of this report.

2022 Notes

On November 17, 2014, the Company issued $600.0 million in aggregate principal amount of 6.125% Senior Notes due 2022. The 2022 Notes were issued at par and mature on November 15, 2022. The Company received net proceeds of $590.0 million after deducting fees of $10.0 million, which are being amortized as deferred financing costs over the life of the 2022 Notes. The net proceeds were used to repay outstanding borrowings under the Company's credit facility and for general corporate purposes.

Prior to November 15, 2017, the Company may redeem, on one or more occasions, up to 35 percent of the aggregate principal amount of the 2022 Notes with the net cash proceeds of certain equity offerings at a redemption price of 106.125% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2022 Notes, in whole or in part, at any time prior to November 15, 2018, at a redemption price equal to 100 percent of the principal amount of the 2022 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after November 15, 2018, the Company may also redeem all or, from time to time, a portion of the 2022 Notes at the redemption prices set forth below, during the twelve-month period beginning on November 15 of each applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2018	103.063	%
2019	101.531	%
2020 and thereafter	100.000	%

Additionally, on November 17, 2014, the Company entered into a registration rights agreement that provides holders of the 2022 Notes certain registration rights under the Securities Act. Pursuant to the registration rights agreement, the Company is required to file an exchange offer registration statement with the SEC with respect to its offer to exchange the 2022 Notes for substantially identical notes that are registered under the Securities Act. Under certain circumstances, the Company has agreed to file a shelf registration statement relating to the resale of the 2022 Notes in lieu of a registered exchange offer. If the registration statement related to the exchange offer is not declared effective on or before November 17, 2015, or if the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, the Company has agreed to pay additional interest with respect to the 2022 Notes in an amount not to exceed one percent of the principal amount of the 2022 Notes until the exchange offer is completed or the shelf registration statement is declared effective.

2024 Notes

On May 20, 2013, the Company issued $500.0 million in aggregate principal amount of 5.0% Senior Notes due 2024. The 2024 Notes were issued at par and mature on January 15, 2024. The Company received net proceeds of $490.2 million after deducting fees of $9.8 million, which are being amortized as deferred financing costs over the life of the 2024 Notes. The net proceeds were used to reduce the Company’s outstanding credit facility balance.

Prior to July 15, 2016, the Company may redeem, on one or more occasions, up to 35 percent of the aggregate principal amount of the 2024 Notes with the net cash proceeds of certain equity offerings at a redemption price of 105% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2024 Notes, in whole or in part, at any time prior to July 15, 2018, at a redemption price equal to 100 percent of the principal amount of the 2024 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after July 15, 2018, the Company may also redeem all or, from time to time, a portion of the 2024 Notes at the redemption prices set forth below, during the twelve-month period beginning on July 15 of each applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2018	102.500	%
2019	101.677	%
2020	100.833	%
2021 and thereafter	100.000	%

Additionally, on May 20, 2013, the Company entered into a registration rights agreement that provides holders of the 2024 Notes certain registration rights under the Securities Act. The Company closed its offer to exchange its 2024 Notes for notes registered under the Securities Act on June 25, 2014.

2023 Notes

On June 29, 2012, the Company issued $400.0 million in aggregate principal amount of 6.50% Senior Notes due 2023. The 2023 Notes were issued at par and mature on January 1, 2023. The Company received net proceeds of $392.1 million after deducting fees of $7.9 million, which are being amortized as deferred financing costs over the life of the 2023 Notes. The net proceeds were used to reduce the Company’s outstanding credit facility balance.

Prior to July 1, 2015, the Company may redeem, on one or more occasions, up to 35 percent of the aggregate principal amount of the 2023 Notes with the net cash proceeds of certain equity offerings at a redemption price of 106.5% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2023 Notes, in whole or in part, at any time prior to July 1, 2017, at a redemption price equal to 100 percent of the principal amount of the 2023 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after July 1, 2017, the Company may also redeem all or, from time to time, a portion of the 2023 Notes at the redemption prices set forth below, during the twelve-month period beginning on July 1 of each applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2017	103.250	%
2018	102.167	%
2019	101.083	%
2020 and thereafter	100.000	%

Additionally, on June 29, 2012, the Company entered into a registration rights agreement that provides holders of the 2023 Notes certain registration rights under the Securities Act. The Company satisfied its obligations to exchange its outstanding $400.0 million of its 2023 Notes for notes registered under the Securities Act on October 30, 2012.

2021 Notes

On November 8, 2011, the Company issued $350.0 million in aggregate principal amount of 6.50% Senior Notes due 2021. The 2021 Notes were issued at par and mature on November 15, 2021. The Company received net proceeds of $343.1 million after deducting fees of $6.9 million, which are being amortized as deferred financing costs over the life of the 2021 Notes. The net proceeds were used for general corporate purposes and to reduce the Company’s outstanding credit facility balance.

The Company may redeem the 2021 Notes, in whole or in part, at any time prior to November 15, 2016, at a redemption price equal to 100 percent of the principal amount, plus a specified make-whole premium and accrued and unpaid interest.

The Company may also redeem all or, from time to time, a portion of the 2021 Notes on or after November 15, 2016, at the prices set forth below, during the twelve-month period beginning on November 15 of the applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2016	103.250	%
2017	102.167	%
2018	101.083	%
2019 and thereafter	100.000	%

Additionally, on November 8, 2011, the Company entered into a registration rights agreement that provides holders of the 2021 Notes certain registration rights for the 2021 Notes under the Securities Act. The Company satisfied its obligations to exchange its outstanding $350.0 million of its 2021 Notes for notes registered under the Securities Act on March 7, 2012.

2019 Notes

On February 7, 2011, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2019. The 2019 Notes were issued at par and mature on February 15, 2019. The Company received net proceeds of $341.1 million after deducting fees of $8.9 million, which are being amortized as deferred financing costs over the life of the 2019 Notes. The net proceeds were used to repay borrowings under the Company's credit facility, to fund the Company's ongoing capital expenditure program, and for general corporate purposes.

The Company may redeem all or, from time to time, a portion of the 2019 Notes on or after February 15, 2015, at the prices set forth in the table below, during the twelve-month period beginning on February 15 of the applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.313	%
2016	101.656	%
2017 and thereafter	100.000	%

Additionally, on February 7, 2011, the Company entered into a registration rights agreement that provides holders of the 2019 Notes certain registration rights for the 2019 Notes under the Securities Act. The Company satisfied its obligations to exchange its outstanding $350.0 million of its 2019 Notes for notes registered under the Securities Act on January 11, 2012.

3.50% Senior Convertible Notes

On April 2, 2012, the Company called for redemption all of its outstanding 3.50% Senior Convertible Notes. The call for redemption resulted in holders of $281.3 million aggregate principal amount electing to convert their notes. The Company settled the principal amount of all converted 3.50% Senior Convertible Notes in cash and settled the excess conversion value by issuing 864,106 shares of its common stock. The Company redeemed the remaining $6.2 million of aggregate principal amount of notes that were not converted on the redemption date at par plus accrued interest in cash. The Company used funds borrowed under its credit facility to pay the cash portion of the settlement.

Capitalized Interest

Capitalized interest costs for the Company for the years ended December 31, 2014, 2013, and 2012, were $16.2 million, $11.0 million, and $12.1 million, respectively.

Note 6 – Commitments and Contingencies

Commitments

The Company has entered into various agreements, which include drilling rig contracts of $116.1 million, gathering, processing, and transportation through-put commitments of $939.4 million, office leases, including maintenance, of $69.3 million, and other miscellaneous contracts and leases of $11.7 million. The annual minimum payments for the next five years and total minimum payments thereafter are presented below:

Years Ending December 31,	(in thousands)
2015	$224,897
2016	147,896
2017	118,320
2018	128,866
2019	132,920
Thereafter	383,619
Total	$1,136,518

Drilling rig contracts

The Company has multiple long-term drilling rig contracts. Early termination of these rig contracts as of December 31, 2014, would result in termination penalties of $75.8 million, which would be in lieu of paying the remaining drilling commitments of $116.1 million included in the table above.

Transportation commitments

The Company has gathering, processing, and transportation through-put commitments with various third parties that require delivery of a minimum amount of 1,411 Bcf of natural gas and 48 MMBbl of crude oil. These contracts expire at various dates through 2028 and the total amount of the commitment is approximately $939.4 million. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment for natural gas is projected, the Company has rights under certain contracts to arrange for third party gas to be delivered, and such volumes would count toward its minimum volume commitment. As of the filing date of this report, the Company does not expect to incur any material shortfalls.

Office leases

The Company leases office space under various operating leases with terms extending as far as 2026. Rent expense for years ended December 31, 2014, 2013, and 2012, was $6.5 million, $5.7 million, and $5.4 million, respectively. The Company also leases office equipment under various operating leases.

Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such pending litigation and claims will not have a material effect on the results of operations, the financial position, or the cash flows of the Company.

Note 7 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan based on a performance measurement framework whereby selected eligible employee participants may be awarded an annual cash bonus. As the plan is currently administered, any awards under the plan are based on Company and regional performance and are then further refined by individual performance. The Company accrues cash bonus expense based upon the Company's current year performance. Included in general and administrative expense, lease operating expense, and exploration expense in the accompanying statements of operations are $37.8 million, $41.8 million, and $16.3 million of cash bonus expense related to the specific performance years ended December 31, 2014, 2013, and 2012, respectively.

Equity Plan

There are several components to the Company's Equity Plan that are described in this section. Various types of equity awards have been granted by the Company in different periods.

As of December 31, 2014, 3.6 million shares of common stock remained available for grant under the Equity Plan. The issuance of a direct share benefit such as a share of common stock, a stock option, a restricted share, a RSU, or a PSU counts as one share against the number of shares available to be granted under the Equity Plan. Each PSU has the potential to count as two shares against the number of shares available to be granted under the Equity Plan based on the final performance multiplier. Stock options were issued out of the St. Mary Land & Exploration Company Stock Option Plan and the St. Mary Land & Exploration Company Incentive Stock Option Plan, both predecessors to the Equity Plan.

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants PSUs to eligible employees as a part of its equity compensation program. The PSU factor is based on the Company's performance after completion of a three-year performance period. The performance criteria for the PSUs are based on a combination of the Company's annualized Total Shareholder Return ("TSR") for the performance period and the relative performance of the Company's TSR compared with the annualized TSR of certain peer companies for the performance period. PSUs are recognized as general and administrative and exploration expense over the vesting periods of the award.

The fair value of PSUs was measured at the grant date with a stochastic process method using the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the three-year performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility, dividend yield, and risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with a three-year vesting period, as well as the volatilities and dividend yields for each of the Company's peers.

Total expense recorded for PSUs was $16.0 million, $16.8 million, and $18.2 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, there was $19.8 million of total unrecognized expense related to PSUs, which is being amortized through 2017.

A summary of the status and activity of non-vested PSUs is presented in the following table:

	For the Years Ended December 31,					
	2014		2013		2012	
	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year (1)	572,469	$ 66.07	669,308	$ 63.91	885,894	$ 57.52
Granted (1)	202,404	$ 94.66	274,831	$ 64.13	314,853	$ 51.98
Vested (1)	(206,830)	$ 64.79	(345,005)	$ 60.06	(493,679)	$ 44.72
Forfeited (1)	(134,383)	$ 86.72	(26,665)	$ 69.74	(37,760)	$ 65.35
Non-vested at end of year(1)	433,660	$ 73.63	572,469	$ 66.07	669,308	$ 63.91

(1) The number of awards assumes a one multiplier. The final number of shares of common stock issued may vary depending on the ending three-year performance multiplier, which ranges from zero to two.

The fair value of the PSUs granted in 2014, 2013, and 2012 was $19.2 million, $17.6 million, and $16.4 million for the 2014, 2013, and 2012 grants, respectively. The PSUs granted in 2013 and 2014 will remain unvested until the third anniversary date of their issuance, at which time they will fully vest. The PSUs granted in 2012 vest 1/3 on each of the first three anniversary dates of their issuance.

The total fair value of PSUs that vested during the years ended December 31, 2014, 2013, and 2012 was $13.4 million, $20.7 million, and $22.1 million, respectively.

During the year ended December 31, 2014, the Company settled PSUs that were granted in 2011, which earned a 0.55-times multiplier, by issuing a net 85,121 shares of the Company's common stock in accordance with the terms of the PSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, 45,042 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs for 2014.

During the year ended December 31, 2013, the Company settled PSUs that were granted in 2010, which earned a 1.725-times multiplier, by issuing a net 387,461 shares of the Company's common stock in accordance with the terms of the PSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, 200,050 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs for 2013.

During the year ended December 31, 2012, the Company settled PSUs that were granted in 2009, which earned a 2.0-times multiplier, by issuing a net 812,562 shares of the Company's common stock in accordance with the terms of the PSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, 406,866 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs for 2012.

Restricted Stock Units Under the Equity Incentive Compensation Plan
The Company grants RSUs to eligible employees as a part of its equity incentive compensation program. Restrictions and vesting periods for the awards are determined by the Compensation Committee of the Board of Directors and are set forth in the award agreements. Each RSU represents a right for one share of the Company’s common stock to be delivered upon settlement of the award at the end of a specified period. RSUs are recognized as general and administrative and exploration expense over the vesting periods of the award.
The total expense associated with RSUs for the years ended December 31, 2014, 2013, and 2012, was $13.9 million, $13.1 million, and $9.8 million, respectively. As of December 31, 2014, there was $22.5 million of total unrecognized expense related to unvested RSU awards, which is being amortized through 2017. The Company records compensation expense associated with the issuance of RSUs based on the fair value of the awards as of the date of grant. The fair value of an RSU is equal to the closing price of the Company’s common stock on the day before grant.
A summary of the status and activity of non-vested RSUs is presented below:

	For the Years Ended December 31,					
	2014		2013		2012	
	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	580,431	$57.05	496,244	$51.81	308,877	$44.33
Granted	234,560	$83.98	329,939	$60.01	379,332	$49.47
Vested	(253,031)	$58.19	(207,376)	$49.73	(166,672)	$32.72
Forfeited	(46,236)	$62.06	(38,376)	$54.37	(25,293)	$51.06
Non-vested at end of year	515,724	$68.29	580,431	$57.05	496,244	$51.81

The fair value of RSUs granted in 2014, 2013, and 2012 was $19.7 million, $19.8 million, and $18.8 million, respectively. The RSUs granted in 2014, 2013, and 2012 vest 1/3 on each of the first three anniversary dates of the awards.
The total fair value of RSUs that vested during the years ended December 31, 2014, 2013, and 2012, was $14.7 million, $10.3 million, and $5.4 million, respectively.
During the years ended December 31, 2014, 2013, and 2012, the Company settled 253,031, 207,378, and 166,670 RSUs, respectively. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued net shares of common stock of 171,597, 139,391, and 116,813 for 2014, 2013, and 2012, respectively. The remaining 81,434, 67,987, and 49,857 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs for 2014, 2013, and 2012, respectively.

Stock Option Grants Under the Equity Incentive Compensation Plan

The Company previously granted stock options under the St. Mary Land & Exploration Company Stock Option Plan and the St. Mary Land & Exploration Company Incentive Stock Option Plan. The last issuance of stock options occurred on December 31, 2004. Stock options to purchase shares of the Company's common stock had been granted to eligible employees and members of the Board of Directors. All options granted under the option plans were granted at exercise prices equal to the respective closing market price of the Company's underlying common stock on the grant dates. All stock options granted under the option plans were exercisable for a period of up to 10 years from the date of grant. The remaining options from the 2004 grant were exercised during the year ended December 31, 2014. As of December 31, 2014, there was no unrecognized compensation expense related to stock option awards.

A summary of activity associated with the Company's Stock Option Plans during the last three years is presented in the following table:

	Shares		Weighted - Average Exercise Price	Aggregate Intrinsic Value
For the year ended December 31, 2012				
Outstanding, start of year	508,214		$13.86	
Exercised	(240,368	)	$12.65	$11,842,575
Forfeited	—		$—	
Outstanding, end of year	267,846		$14.95	$9,983,177
Vested and exercisable at end of year	267,846		$14.95	$9,983,177
For the year ended December 31, 2013				
Outstanding, start of year	267,846		$14.95	
Exercised	(228,758	)	$13.92	$12,326,994
Forfeited	—		$—	
Outstanding, end of year	39,088		$20.87	$2,432,837
Vested and exercisable at end of year	39,088		$20.87	$2,432,837
For the year ended December 31, 2014				
Outstanding, start of year	39,088		$20.87	
Exercised	(39,088	)	$20.87	$1,993,726
Forfeited	—		$—	
Outstanding, end of year	—		$—	$—
Vested and exercisable at end of year	—		$—	$—

The fair value of options was measured at the date of grant using the Black-Scholes-Merton option-pricing model. Cash flows resulting from excess tax benefits are classified as part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for vested RSUs, settled PSUs, and exercised options in excess of the deferred tax asset attributable to stock compensation costs for such equity awards. The Company recorded no excess tax benefits for the years ended December 31, 2014, 2013, and 2012. Cash received from exercises under all share-based payment arrangements for the years ended December 31, 2014, 2013, and 2012, was $4.0 million, $3.2 million, and $3.0 million, respectively.

Director Shares

In 2014, 2013, and 2012, the Company issued 27,677, 28,169, and 30,486 shares, respectively, of the Company's common stock to its non-employee directors pursuant to the Company's Equity Plan. The Company recorded compensation expense related to these issuances of $1.6 million, $1.4 million, and $1.3 million for the years ended December 31, 2014, 2013, and 2012, respectively.

All shares of common stock issued to the Company's non-employee directors are earned over the one-year service period following the date of grant, unless five years of service has been provided by the director, in which case that director's shares vest immediately.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in fair market value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period. All shares issued under the ESPP on or after December 31, 2011, have no minimum restriction period. The ESPP is intended to qualify under Section 423 of the IRC. The Company has 1.1 million shares available under the ESPP for issuance as of December 31, 2014. Shares issued under the ESPP totaled 83,136 in 2014, 77,427 in 2013, and 66,485 in 2012. Total proceeds to the Company for the issuance of these shares were $4.1 million, $3.7 million, and $2.8 million for the years ended December 31, 2014, 2013, and 2012, respectively.

The fair value of ESPP shares was measured at the date of grant using the Black-Scholes-Merton option-pricing model. Expected volatility was calculated based on the Company's historical daily common stock price, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with a six month vesting period.

The fair value of ESPP shares issued during the periods reported were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,					
	2014		2013		2012	
Risk free interest rate	0.1	%	0.1	%	0.1	%
Dividend yield	0.1	%	0.2	%	0.2	%
Volatility factor of the expected market price of the Company's common stock	33.0	%	41.1	%	47.8	%
Expected life (in years)	0.5		0.5		0.5	

The Company expensed $1.1 million, $1.1 million, and $948,000 for the years ended December 31, 2014, 2013, and 2012, respectively, based on the estimated fair value of grants.

401(k) Plan

The Company has a defined contribution pension plan (the “401(k) Plan”) that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute a maximum of 60 percent of their base salaries up to the contribution limits established under the IRC. The Company matches each employee’s contribution up to six percent of the employee’s base salary and may make additional contributions at its discretion. Beginning in 2014, the Company also matches employee contributions up to six percent of the employee’s bonus paid pursuant to the Company’s cash bonus plan. The Company’s matching contributions to the 401(k) Plan were $6.4 million, $4.2 million, and $3.5 million for the years ended December 31, 2014, 2013, and 2012, respectively. No discretionary contributions were made by the Company to the 401(k) Plan for any of these years.

Non-qualified Deferred Compensation Plan

In January 2014, the Company established a non-qualified deferred compensation (“NQDC”) plan intended to provide plan participants with the ability to plan for income tax events and the opportunity to receive a benefit for matching contributions in excess of IRC limits applicable to the Company’s 401(k) plan. The NQDC plan is designed to allow employee participants to defer a portion of base salary and cash bonuses paid pursuant to the Company’s cash bonus plan and director participants to defer a portion of the cash retainer paid to directors. Each year, participating employees may elect to defer (i) between 0% and 50% of their base salary and (ii) between 0% and 100% of the cash bonus paid pursuant to the cash bonus plan, and participating directors may elect to defer between 0% and 100% of their cash retainer. The NQDC plan requires the Company to make contributions for each eligible employee equal to 100% of the deferred amount for such employee, limited to 6% of such employee’s base salary and cash bonus. Each eligible employee’s interest in contributions made by the Company will vest 40% after the second year of such employee’s service to the Company, and 20% per year thereafter. A participant’s account will be distributed based upon the participant’s payment election made at the time of deferral. A participant may elect to have distributions made in lump sum or in annual installments ranging for a period from 1 to 10 years. Participants in the NQDC plan are currently limited to the Company’s officers and directors.

Net Profits Plan

Under the Company’s Net Profits Plan, all oil and gas wells that were completed or acquired during each year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Compensation Committee of the Company’s Board of Directors and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, 10 percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the 10 percent level. In December 2007, the Board of Directors discontinued the creation of new pools under the Net Profits Plan. As a result, the 2007 pool was the last Net Profits Plan pool established by the Company.

Cash payments made or accrued under the Net Profits Plan that have been recorded as either general and administrative expense or exploration expense are detailed in the table below:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
General and administrative expense	$8,326	$13,734	$15,565
Exploration expense	690	1,310	1,751
Total	$9,016	$15,044	$17,316

Additionally, the Company made or accrued cash payments under the Net Profits Plan of $8.3 million, $10.3 million, and $2.3 million for the years ended December 31, 2014, 2013, and 2012, respectively, as a result of divestiture proceeds. The cash payments are accounted for as a reduction in the gain (loss) on divestiture activity line item in the accompanying statements of operations.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. If the Company allocated the change in liability to these specific functional line items, based on the current allocation of actual distributions made by the Company, such expenses or benefits would predominately be allocated to general and administrative expense. The amount that would be allocated to exploration expense is minimal in comparison. Over time, less of the amount distributed relates to prospective exploration efforts as more of the amount distributed is paid to employees that have terminated employment and do not provide ongoing exploration support to the Company.

Note 8 – Pension Benefits

The Company has a non-contributory defined benefit pension plan covering substantially all employees who meet age and service requirements (the “Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (the “Nonqualified Pension Plan” and together with the Qualified Pension Plan, the “Pension Plans”).

Obligations and Funded Status for the Pension Plans

The Company recognizes the funded status, (i.e. the difference between the fair value of plan assets and the projected benefit obligation) of the Company’s Pension Plans in the accompanying balance sheets as either an asset or a liability and recognizes a corresponding adjustment to accumulated other comprehensive income, net of tax. The projected benefit obligation is the actuarial present value of the benefits earned to date by plan participants based on employee service and compensation including the effect of assumed future salary increases. The accumulated benefit obligation uses the same factors as the projected benefit obligation but excludes the effects of assumed future salary increases. The Company’s measurement date for plan assets and obligations is December 31.

	For the Years Ended December 31,	
	2014	2013
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$43,285	$40,237
Service cost	6,335	6,291
Interest cost	2,191	1,627
Plan amendments	—	—
Actuarial (gain) loss	8,821	(1,577)
Benefits paid	(2,765)	(3,293)
Projected benefit obligation at end of year	57,867	43,285
Change in plan assets:		
Fair value of plan assets at beginning of year	24,658	20,254
Actual return on plan assets	737	2,726
Employer contribution	5,310	4,971
Benefits paid	(2,765)	(3,293)
Fair value of plan assets at end of year	27,940	24,658
Funded status at end of year	$(29,927)	$(18,627)

The Company’s underfunded status for the Pension Plans for the years ended December 31, 2014 and 2013, is $29.9 million and $18.6 million, respectively, and is recognized in the accompanying balance sheets as a portion of other noncurrent liabilities. No plan assets of the Qualified Pension Plan were returned to the Company during the fiscal year ended December 31, 2014. There are no plan assets in the Nonqualified Pension Plan.

Accumulated Benefit Obligation in Excess of Plan Assets for the Pension Plans

	As of December 31,	
	2014	2013
	(in thousands)	
Projected benefit obligation	$57,867	$43,285
Accumulated benefit obligation	$43,205	$32,396
Less: Fair value of plan assets	(27,940)	(24,658)
Underfunded accumulated benefit obligation	$15,265	$7,738

Pension expense is determined based upon the annual service cost of benefits (the actuarial cost of benefits earned during a period) and the interest cost on those liabilities, less the expected return on plan assets. The expected long-term rate of return on plan assets is applied to a calculated value of plan assets that recognizes changes in fair value over a five-year period. This practice is intended to reduce year-to-year volatility in pension expense, but it can have the effect of delaying recognition of differences between actual returns on assets and expected returns based on long-term rate of return assumptions. Amortization of unrecognized net gain or loss resulting from actual experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of net periodic benefit cost for a year. If, as of the beginning of the year, the unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation and the market-related value of plan assets, then the amortization is the excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.

Pre-tax amounts not yet recognized in net periodic pension costs, but rather recognized in accumulated other comprehensive loss as of December 31, 2014 and 2013, consist of:

	As of December 31,	
	2014	2013
	(in thousands)	
Unrecognized actuarial losses	$17,812	$8,439
Unrecognized prior service costs	118	136
Unrecognized transition obligation	—	—
Accumulated other comprehensive loss	$17,930	$8,575

The estimated net loss that will be amortized from accumulated other comprehensive loss into net periodic benefit cost over the next fiscal year is $1.2 million.

Pre-tax changes recognized in other comprehensive income (loss) during 2014, 2013, and 2012, were as follows:

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Net actuarial gain (loss)	$(10,062)	$2,766	$(4,680)
Prior service cost	—	—	—
Less: Amortization of:			
Prior service cost	(17)	(17)	(17)
Actuarial loss	(689)	(1,222)	(754)
Total other comprehensive income (loss)	$(9,356)	$4,005	$(3,909)

Components of Net Periodic Benefit Cost for the Pension Plans

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Components of net periodic benefit cost:			
Service cost	$6,335	$6,291	$4,934
Interest cost	2,191	1,627	1,374
Expected return on plan assets that reduces periodic pension cost	(1,978)	(1,538)	(1,165)
Amortization of prior service cost	17	17	17
Amortization of net actuarial loss	689	1,222	754
Net periodic benefit cost	$7,254	$7,619	$5,914

Gains and losses in excess of 10 percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Pension Plan Assumptions

Weighted-average assumptions to measure the Company's projected benefit obligation and net periodic benefit cost are as follows:

	As of December 31,		
	2014	2013	2012
Projected benefit obligation			
Discount rate	4.3%	5.0%	3.9%
Rate of compensation increase	6.2%	6.2%	6.2%
Net periodic benefit cost			
Discount rate	5.0%	3.9%	4.7%
Expected return on plan assets (1)	7.5%	7.5%	7.5%
Rate of compensation increase	6.2%	6.2%	6.2%

(1) There is no assumed expected return on plan assets for the Nonqualified Pension Plan because there are no plan assets in the Nonqualified Pension Plan.

The Company's pension investment policy includes various guidelines and procedures designed to ensure that assets are prudently invested in a manner necessary to meet the future benefit obligation of the Pension Plans. The policy does not permit the direct investment of plan assets in the Company's securities. The Qualified Pension Plan's investment horizon is long-term and accordingly the target asset allocations encompass a strategic, long-term perspective of capital markets, expected risk and return behavior and perceived future economic conditions. The key investment principles of diversification, assessment of risk, and targeting the optimal expected returns for given levels of risk are applied.

The Qualified Pension Plan's investment portfolio contains a diversified blend of investments, which may reflect varying rates of return. The investments are further diversified within each asset classification. This portfolio diversification provides protection against a single security or class of securities having a disproportionate impact on aggregate investment performance. The actual asset allocations are reviewed and rebalanced on a periodic basis to maintain the target allocations. The weighted-average asset allocation of the Qualified Pension Plan is as follows:

	Target		As of December 31,			
Asset Category	2015		2014		2013	
Equity securities	42.0	%	39.6	%	43.6	%
Fixed income securities	35.0	%	33.9	%	32.2	%
Other securities	23.0	%	26.5	%	24.2	%
Total	100.0	%	100.0	%	100.0	%

There is no asset allocation of the Nonqualified Pension Plan since there are no plan assets in that plan. An expected return on plan assets of 7.5 percent was used to calculate the Company's obligation under the Qualified Pension Plan for 2014 and 2013. Factors considered in determining the expected rate of return include the long-term historical rate of return provided by the equity and debt securities markets and input from the investment consultants and trustees managing the plan assets. The difference in investment income using the projected rate of return compared to the actual rates of return for the past two years was not material and is not expected to have a material effect on the accompanying statements of operations or cash flows from operating activities in future years.

Fair Value Assumptions

The fair values of the Company's Qualified Pension Plan assets as of December 31, 2014 and 2013, utilizing the fair value hierarchy discussed in Note 11 – Fair Value Measurements is as follows:

	Actual Asset Allocation		Total	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(in thousands)			
December 31, 2014						
Cash	—	%	$—	$—	$—	$—
Equity Securities						
Domestic [1]	27.1	%	7,569	5,550	2,019	—
International [2]	12.5	%	3,498	3,498	—	—
Total Equity Securities	39.6	%	11,067	9,048	2,019	—
Fixed Income Securities						