SM Energy Co
Form 10-K
February 24, 2016

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, 2015
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 66,782,794 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, 2015, the last business day of the registrant's most recently completed second fiscal quarter, of $46.12 per share, as reported on the New York Stock Exchange, was $3,080,022,459. 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 17, 2016, the registrant had 68,077,546 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 2016 annual meeting of stockholders to be filed within 120 days after December 31, 2015.

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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" 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 profitably 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 growth opportunities through both exploration and acquisitions, and seek to maximize the value of our assets through industry-leading technology application and outstanding operational execution. We focus on achieving high full-cycle economic returns on our investments and maintaining a simple, strong balance sheet through a conservative approach to leverage.

Significant Developments in 2015

- Production. We achieved record levels of production for 2015. Our average daily production was composed of 52.7 MBbl of oil, 475.7 MMcf of gas, and 44.0 MBbl of NGLs, for an average equivalent production rate of 175.9 MBOE per day, which was an increase of 16 percent from an average of 151.1 MBOE per day in 2014. Please refer to Core Operational Areas below for additional discussion.
- Reserves and Capital Investment. Our estimated proved reserves decreased 14 percent to 471.3 MMBOE at December 31, 2015, from 547.7 MMBOE at December 31, 2014, of which 25.4 MMBOE related to the divestiture of proved reserves. We added 160.6 MMBOE through drilling activities during the year, led by our activities in the Eagle Ford shale and Bakken/Three Forks resource plays. Costs incurred for drilling and exploration activities, excluding acquisitions, decreased 34 percent to $1.4 billion in 2015 when compared to 2014. We had strong reserve additions as a result of our success in reducing costs, optimizing completions, and generating better well results in our core development programs; however, these additions were offset by the impact of lower commodity prices. Our proved reserve life decreased to 7.3 years in 2015 compared to 9.9 years in 2014. Please refer to Reserves and Core Operational Areas below for additional discussion.
- Increased Liquidity. During 2015, we extended the maturity of a portion of our long-term debt by using the proceeds from our issuance of $500.0 million in aggregate principal amount of 5.625% Senior Notes due 2025 to redeem the $350.0 million principal amount of our 6.625% Senior Notes due 2019. The earliest maturity for any of our Senior Notes occurs in 2021. Please refer to Overview of Liquidity

and Capital Resources in Part II, Item 7 of this report for additional discussion on our current and future liquidity.

- Divestiture Activity. During 2015, we divested a total of 25.4 MMBOE of proved reserves in multiple transactions for aggregate cash proceeds of approximately $357.9 million. Our most significant divestiture activity was the sale of our Mid-Continent assets in the second quarter of 2015.
- Sustained Low 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 continued to decline throughout 2015. The daily NYMEX spot price ranged from a high of $61.43 per Bbl in June to a low of $34.73 per Bbl in December. Oil prices declined further subsequent to year end 2015, dropping to a 12-year low of $26.21 per Bbl in February 2016. The average NYMEX price decreased to $48.68 per Bbl in 2015 compared to $93.03 per Bbl in 2014.

Natural gas prices have been under downward pressure over the past several years due to high levels of supply and remained highly volatile during 2015. The daily NYMEX spot price ranged from a high of $3.29 per MMBtu in January to a low of $1.53 per MMBtu in December. The average NYMEX price decreased in 2015 to $2.61 per MMBtu compared to $4.35 per MMBtu in 2014.

NGL prices continued to decrease in 2015 in line with oil price declines. The monthly OPIS NGL price ranged from a high of $22.57 per Bbl in February to a low of $17.07 per Bbl in December. NGL prices declined further subsequent to year end 2015, dropping to a low of $14.73 per Bbl in January 2016. The average OPIS price decreased in 2015 to $19.76 per Bbl compared to $38.93 per Bbl in 2014.

- Impairments. We recorded impairment of proved properties expense of $468.7 million, abandonment and impairment of unproved properties expense of $78.6 million, and impairment of other property and equipment expense of $49.4 million for the year ended December 31, 2015. These impairments were largely due to commodity price declines, which impacted our Powder River Basin program and certain legacy and non-core assets, as well as our decision to reduce capital invested in the development of our east Texas exploration program in light of the sustained, low commodity price environment.

Outlook for 2016

Our goal is to maintain a strong balance sheet and preserve liquidity in the current commodity price environment. We expect to incur capital expenditures below adjusted EBITDAX in order to minimize any impact to our total debt. We believe this focus on our liquidity will best preserve our balance sheet and will give us the flexibility to adapt as industry conditions change.

Our capital program for 2016 will be approximately $705 million, of which, approximately 85 percent will be invested in drilling and completion activities, with the focus on our core development programs in the Bakken/Three Forks, Permian Basin, and Eagle Ford shale. We plan to continue our focus on conducting safe operations even as we pursue cost saving measures throughout our business. Please refer to Outlook for 2016 under Part II, Item 7 of this report for additional discussion concerning our capital plans for 2016.

Core Operational Areas

Our 2015 operations were concentrated in four onshore operating areas in the United States. We divested our Mid-Continent assets during the second quarter of 2015. The following table summarizes estimated proved reserves, PV-10, production, and costs incurred in oil and gas activities for the year ended December 31, 2015, for our core operating areas:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent [2]	Total [1]
Proved Reserves					
Oil (MMBbl)	43.6	88.2	13.4	—	145.3
Gas (Bcf)	1,116.9	102.9	44.2	—	1,264.0
NGLs (MMBbl)	112.6	2.8	—	—	115.4
MMBOE [1]	342.4	108.1	20.8	—	471.3
Relative percentage	73 %	23 %	4 %	— %	100 %
Proved Developed %	50 %	57 %	49 %	— %	52 %
PV-10 (in millions) [3]					
Proved Developed	$793.4	$667.3	$132.3	$—	$1,593.0
Proved Undeveloped	52.1	129.3	16.1	—	197.5
Total Proved	$845.5	$796.6	$148.4	$—	$1,790.5
Relative percentage	47 %	45 %	8 %	— %	100 %
Production					
Oil (MMBbl)	7.9	9.5	1.8	—	19.2
Gas (Bcf)	149.5	9.3	5.1	9.7	173.6
NGLs (MMBbl)	15.7	0.3	—	—	16.1
MMBOE [1]	48.5	11.3	2.7	1.7	64.2
Avg. Daily Equivalents (MBOE/d)	132.9	31.1	7.4	4.6	175.9
Relative percentage	75 %	18 %	4 %	3 %	100 %
Costs Incurred (in millions)[4]	$765.3	$538.5	$59.4	$9.0	$1,395.0

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

(2) We divested our Mid-Continent assets in the second quarter of 2015.

(3) 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.

(4) 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.

In general, we reduced our capital spending activity across all regions during 2015 in light of the low commodity price environment. We had strong proved reserve additions and positive performance revisions for the year ended December 31, 2015, especially in our Eagle Ford shale and Bakken/Three Forks resource plays; however, our total estimated proved reserves decreased from year-end 2014 due to the divestiture of our Mid-Continent assets, a significant negative price revision, and the removal of proved undeveloped reserves related to changes in our development plan.

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 197,000 net acres. Our operated program accounts for approximately 80 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. Our development program has shifted to utilizing longer laterals and completions with higher sand loadings, which is

resulting in improved well performance as shown in our positive performance revision to our proved reserves for the year ended December 31, 2015.
A significant portion of our 2015 capital was deployed in our South Texas & Gulf Coast region in our operated and outside-operated Eagle Ford shale programs. We incurred $765.3 million of costs to add approximately 119.3 MMBOE of estimated proved reserves through our drilling activities. As of December 31, 2015, we had 76 gross and net wells that had been drilled but not completed in our operated Eagle Ford shale program. Production for 2015 increased 21 percent over 2014 to 48.5 MMBOE. Estimated proved reserves decreased 13 percent at year-end 2015 to 342.4 MMBOE from 394.6 MMBOE at year-end 2014.
Rocky Mountain Region. Operations in our Rocky Mountain region are managed from our office in Billings, Montana. We have approximately 162,000 net acres being actively developed in the Bakken and Three Forks formations. During 2015, we focused on testing completion optimizations and down-spacing in Divide County, North Dakota.

In the Powder River Basin, we have approximately 204,000 net acres, a large portion of which are prospective for the Frontier and Shannon intervals. Given the current commodity price environment, we have reduced our activity in the Powder River Basin.

We incurred $538.5 million of costs to add approximately 34.6 MMBOE of estimated proved reserves in our Rocky Mountain region through our drilling activities. As of December 31, 2015, we had 48 gross (40 net) drilled but not completed wells in our operated Bakken/Three Forks program. Production for 2015 increased 30 percent over 2014 to 11.3 MMBOE. Estimated proved reserves slightly decreased to 108.1 MMBOE at year-end 2015 from 108.4 MMBOE at year-end 2014.

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. As of December 31, 2015, we had approximately 23,000 net acres in our Permian region, a large portion of which is held by production. We began 2015 with one operated drilling rig and dropped this rig during the second quarter of 2015.
Costs incurred in our Permian region decreased to $59.4 million in 2015 compared to $195.4 million in 2014. Estimated proved reserves increased four percent to 20.8 MMBOE at year-end 2015 from 20.0 MMBOE at year-end 2014. Production decreased three percent to 2.7 MMBOE in 2015 from 2.8 MMBOE in 2014.
Mid-Continent Region. During the second quarter of 2015, we divested our Mid-Continent assets located in the Arkoma Basin of Oklahoma and Arklatex area of east Texas and northern Louisiana. We also closed our regional office in Tulsa, Oklahoma in mid-2015.

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, 2015. 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 $50.28 per Bbl for oil, $2.59 per MMBtu for natural gas, and $20.20 per Bbl for NGLs for the year ended December 31, 2015. We then adjust these prices to reflect appropriate 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 term in the Glossary of Oil and Gas Terms section of this report for information describing how this metric is calculated.

The following table summarizes estimated proved reserves, PV-10, and standardized measure of discounted future cash flows as of December 31, 2015, 2014, and 2013:

	As of December 31,					
	2015		2014		2013	
Reserve data:						
Proved developed						
Oil (MMBbl)	75.6		89.3		70.2	
Gas (Bcf)	644.4		784.6		569.2	
NGLs (MMBbl)	61.5		66.7		43.8	
MMBOE (1)	244.5		286.8		208.9	
Proved undeveloped						
Oil (MMBbl)	69.6		80.4		56.3	
Gas (Bcf)	619.7		682.0		620.1	
NGLs (MMBbl)	53.9		66.8		60.2	
MMBOE (1)	226.8		260.9		219.9	
Total Proved (1)						
Oil (MMBbl) (1)	145.3		169.7		126.6	
Gas (Bcf) (1)(2)	1,264.0		1,466.5		1,189.3	
NGLs (MMBbl) (1)	115.4		133.5		103.9	
MMBOE (1)	471.3		547.7		428.7	
Proved developed reserves %	52	%	52	%	49	%
Proved undeveloped reserves %	48	%	48	%	51	%
Reserve data (in millions):						
Proved developed PV-10	$1,593.0		$5,253.0		$3,898.6	
Proved undeveloped PV-10	197.5		2,363.9		1,629.9	
Total proved PV-10	$1,790.5		$7,616.9		$5,528.5	
Standardized measure of discounted future net cash flows	$1,868.9		$5,698.8		$4,009.4	
Reserve life (years)	7.3		9.9		8.9	

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

(2) As of December 31, 2015, proved gas reserves contain 48.1 Bcf of gas that we expect to produce and use as field fuel (primarily for compressors).

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,		
	2015	2014	2013
	(in millions)		
Standardized measure of discounted future net cash flows	$1,868.9	$5,698.8	$4,009.4
Add: 10 percent annual discount, net of income taxes	1,228.7	3,407.2	2,500.6
Add: future undiscounted income taxes	—	3,511.4	2,722.2
Undiscounted future net cash flows	3,097.6	12,617.4	9,232.2
Less: 10 percent annual discount without tax effect	(1,307.1)	(5,000.5)	(3,703.7)
PV-10	$1,790.5	$7,616.9	$5,528.5

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, 2015, 2.8 MMBOE of proved undeveloped reserves have been on our books in excess of five years. These reserves are associated with three wells that were drilled in 2015 and are scheduled to be completed and producing in 2016.

For locations that are more than one location removed from developed producing locations, we utilized reliable geologic and engineering technology to add approximately 76.4 MMBOE of proved undeveloped reserves in the more developed portions of our Eagle Ford shale position, 5.1 MMBOE of proved undeveloped reserves in the more developed portions of our Bakken/Three Forks shale position, and 0.4 MMBOE of proved undeveloped reserves in the more developed portion of our Wolfcamp shale position in the Permian Basin. 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, 2015, we had 226.8 MMBOE of proved undeveloped reserves, which is a decrease of 34.1 MMBOE, or 13 percent, from 260.9 MMBOE at December 31, 2014. The following table provides a reconciliation of our proved undeveloped reserves for the year ended December 31, 2015:

	Total (MMBOE)	
Total proved undeveloped reserves:		
Beginning of year	260.9	
Revisions of previous estimates (1)	(35.4	)
Additions from discoveries, extensions, and infill (2)	119.6	
Sales of reserves	(4.3	)
Purchases of minerals in place	0.9	
Removed for five-year rule (3)	(79.4	)
Conversions to proved developed (4)	(35.5	)
End of year	226.8	

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(1) Revisions of previous estimates primarily relate to a negative price revision of 57.0 MMBOE due to the decline in commodity prices during 2015. The negative price revision was partially offset by positive performance revisions totaling 21.6 MMBOE primarily in our Eagle Ford shale and Bakken/Three Forks resource plays due to improved performance related to enhanced completions and reductions in operating expenses, which extended the economic lives of the wells.

(2) We added 98.6 MMBOE of infill proved undeveloped reserves primarily in our Eagle Ford shale and Bakken/Three Forks resource plays, as well as an additional 21.0 MMBOE of proved undeveloped reserves through extensions and discoveries, primarily in our Eagle Ford shale play.

(3) Proved undeveloped reserves were reduced by 79.4 MMBOE due to changes in our development plan, which caused these locations to be reclassified primarily to the probable reserves category due to the five-year rule. These locations were replaced by higher quality proved undeveloped reserves, which are classified as extensions or infills in the table above, and resulted from our testing and delineation programs implemented during 2015.

(4) Conversions of proved undeveloped reserves to proved developed reserves were primarily in our Eagle Ford shale and Bakken/Three Forks resource plays. During 2015, we incurred approximately $415 million on projects associated with reserves booked as proved undeveloped reserves at the end of 2014. Our 2015 track record and development pace were both below 20 percent. This was due to delineation and testing of an incremental landing zone in our Eagle Ford shale asset, delineation and testing of the Bakken interval, step-out drilling on acreage acquired late in 2014 in our Divide County, North Dakota position, and due to the large reserve volumes associated with drilled and uncompleted wells at year-end 2015. At December 31, 2015, drilled but uncompleted wells represent 59.2 MMBOE of total proved undeveloped reserves. Our multi-year historical track is in excess of 20 percent.

As of December 31, 2015, estimated future development costs relating to our proved undeveloped reserves are approximately $478 million, $344 million, and $465 million in 2016, 2017, and 2018, 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 Engineering Manager - Corporate Reserves, subject to the oversight of our management and the Audit Committee of our Board of Directors, as discussed below. Our Engineering Manager - Corporate 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 Engineering Manager - Corporate

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 2015 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,		
	2015	2014	2013
Net production			
Oil (MMBbl)	19.2	16.7	13.9
Gas (Bcf)	173.6	152.9	149.3
NGLs (MMBbl)	16.1	13.0	9.5
MMBOE (2)	64.2	55.1	48.3
Eagle Ford net production (1)			
Oil (MMBbl)	7.6	6.9	5.1
Gas (Bcf)	147.2	120.6	97.1
NGLs (MMBbl)	15.6	12.7	9.2
MMBOE (2)	47.7	39.7	30.5
Realized price			
Oil (per Bbl)	$41.49	$80.97	$91.19
Gas (per Mcf)	$2.57	$4.58	$3.93
NGLs (per Bbl)	$15.92	$33.34	$35.95
Per BOE	$23.36	$45.01	$45.50
Production costs per BOE			
Lease operating expense	$3.73	$4.28	$4.49
Transportation costs	$6.02	$6.11	$5.34
Production taxes	$1.13	$2.13	$2.19
Ad valorem tax expense	$0.39	$0.46	$0.33

(1) In each of the years 2015, 2014, and 2013, 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 calculate due to rounding.

Productive Wells

As of December 31, 2015, we had working interests in 1,459 gross (872 net) productive oil wells and 1,772 gross (653 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 when it first commenced production, but such designation may not be indicative of current production.

Drilling and Completion Activity

All of our drilling and completion activities are conducted by 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 2015, 2014, and 2013, 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,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	87	56.5	133	66.1	154	75.4
Gas	272	100.8	476	165.5	443	162.5
Non-productive	—	—	8	5.3	10	8.5
	359	157.3	617	236.9	607	246.4
Exploratory wells:						
Oil	5	3.5	5	3.0	6	5.1
Gas	1	1.0	7	4.8	4	2.4
Non-productive	5	4.1	4	3.3	1	0.3
	11	8.6	16	11.1	11	7.8
Total	370	165.9	633	248.0	618	254.2

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 to justify completion, or upon completion, the economic operation of a well.

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 2015 (included in the table above), as of January 31, 2016, we were participating in the drilling of 33 gross wells. We operate 9 of these wells on a gross basis (7.5 on a net basis) and other companies operate the remaining 24 gross wells (4 on a net basis). With respect to completion activity, at such date, there were 364 gross wells in which we have an interest that were being completed or waiting on completion. We operate 143 of these wells on a gross basis (134 on a net basis) and were participating in 221 gross (38 on a net basis) outside-operated wells.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leasehold, fee properties, and mineral servitudes that we hold as of December 31, 2015. Undeveloped acreage includes leasehold interests containing proved undeveloped reserves.

	Developed Acres (1)		Undeveloped Acres (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
South Texas & Gulf Coast:						
Operated Eagle Ford	68,773	66,027	98,178	95,447	166,951	161,474
Outside-operated Eagle Ford	137,348	24,089	100,015	11,869	237,363	35,958
Other	22,083	8,649	204,647	163,988	226,730	172,637
Rocky Mountain:						
North Rockies:						
Divide	144,542	90,639	41,450	26,647	185,992	117,286
Raven	48,693	30,466	5,136	1,163	53,829	31,629
Bear Den	21,763	11,233	4,937	1,555	26,700	12,788
Stateline MT	21,102	16,289	12,740	6,718	33,842	23,007
Other	74,921	51,400	298,599	208,365	373,520	259,765
South Rockies:						
PRB Cretaceous	75,035	52,726	193,815	151,655	268,850	204,381
Other	1,556	1,472	126,212	102,642	127,768	104,114
Permian:						
Sweetie Peck	13,228	13,177	521	521	13,749	13,698
Other	12,439	7,534	1,831	1,457	14,270	8,991
Other	10,499	10,499	22,604	17,583	33,103	28,082
Total (3)	651,982	384,200	1,110,685	789,610	1,762,667	1,173,810

(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) As of the filing date of this report, approximately 144,100, 85,300, and 26,700 net acres are scheduled to expire by December 31, 2016, 2017, and 2018, respectively, if production is not established or we take no other action to extend the terms of the applicable lease or leases. Our east Texas acreage, which has been impaired as of December 31, 2015, represents more than 50 percent of the net acres scheduled to expire over the next three years.

Delivery Commitments

As of December 31, 2015, we had gathering, processing, and transportation throughput 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 2,277 Bcf of natural gas and 36 MMBbl of oil through 2028, of which the first 1,059 Bcf of natural gas delivered under a certain agreement does not have a deficiency payment. 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. In the event that no product is delivered in accordance with these agreements, the aggregate undiscounted deficiency payments would be approximately $864.0 million as of December 31, 2015.

Subsequent to December 31, 2015, we entered into amendments to oil and gas gathering agreements related to certain of our Eagle Ford shale assets, neither of which previously had a minimum volume commitment, in order to obtain more favorable rates and terms. Under these amendments, we are now committed to deliver 310 Bcf of natural gas and 41 MMBbl of oil through 2034. In the event that we deliver no product, the aggregate undiscounted deficiency payments under these amended agreements would be approximately $360.8 million. Subsequent to December 31, 2015, we also entered into an amendment to a gas gathering agreement related to certain other Eagle Ford shale assets, which reduced our volume commitment amount as of December 31, 2015, by 829 Bcf and the aggregate undiscounted deficiency payments by $118.2 million. As a result of these subsequent amendments, the aggregate undiscounted deficiency payments as of December 31, 2015, would have been approximately $1.1 billion.

As of the filing date of this report, 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 2015 and 2014, we had one major customer that represented approximately 21 percent and 19 percent, respectively, of our total production revenue, which is discussed in the next paragraph. In 2015 and 2014, we also sold to four entities that are under common ownership. In aggregate, these four entities represented approximately 10 percent and 14 percent of our total production revenue in 2015 and 2014, respectively; however, none of these entities individually represented more than 10 percent of our production revenue. Additionally, in 2015 we sold to three entities that are under common ownership, which in aggregate represented 11 percent of our total production revenue; however, none of these entities individually represented more than 10 percent of our production revenue. During 2013, we had three major customers that represented approximately 26 percent, 16 percent, and 12 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 throughput commitments for up to 10 years pursuant to each contract. While our joint venture partner is the first purchaser under these contracts, representing 21 percent and 19 percent of our total production revenue in 2015 and 2014, respectively, 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 from other areas.

Employees and Office Space
As of February 17, 2016, we had 786 full-time employees. This is an approximate 12 percent decrease from the 896 reported full-time employees as of February 18, 2015. 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, 2015, including our corporate headquarters and regional offices:

Region	Approximate Square Footage Leased
Corporate	108,000
South Texas & Gulf Coast	64,000
Rocky Mountain	44,000
Permian	54,000
Mid-Continent [1]	50,000
Total	320,000

(1) During the third quarter of 2015, we vacated our office space in Tulsa, Oklahoma. We have subleased this space through 2019 and our lease expires in 2022.

In addition to the leased office space in the table above, we own a total of 72,000 square feet of office space.
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 divert gas that traditionally is placed into storage. This could reduce the typical seasonal price differential. 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 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, 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 to increase 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, imposing bond requirements in order to drill or operate wells, and governing 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.
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 closing pits and plugging 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 United States 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. As 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 or other federal agencies, 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. We have 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 (the “Exchange Act”). 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,” “project,” “will,” and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear throughout 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;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- the drilling of wells and other exploration and development activities and plans, as well as possible 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;
- 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; 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 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.
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.
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.

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. The decline in commodity prices during 2015 resulted in reductions to our proved reserve volumes and PV-10; reductions in revenues received from the sale of oil, gas, and NGLs, and thus cash flow from operating activities; and recorded impairments of proved, unproved, and other property. Please refer herein to the captions Significant Developments in 2015 within Part I, Items 1 and 2 Business and Properties; the section Comparison of Financial Results and Trends between 2015 and 2014 and between 2014 and 2013 within Part II, Item 7, and Note 1 – Summary of Significant Accounting Policies and Note 11 – Fair Value Measurements in Part II, Item 8 for specific discussion.

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 prices 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 further decrease or if we encounter operating difficulties that result in our cash flows from operations being less than expected, we may further 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. Our credit ratings were recently downgraded by two major rating agencies. These downgrades and any further downgrades may make it more difficult or expensive for us to borrow additional funds.

During 2015, our revenues decreased significantly from 2014 due to continued declines in commodity prices; however, we were able to fund our capital program through cash flows from operations, proceeds from divestitures, and financing activities. If our revenues continue to decrease in the future 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.

The recent or future downgrades in our credit ratings by various credit rating agencies could impact our access to capital and materially adversely affect our business and financial condition.

In February 2016, Moody’s Investors Service and Standard & Poor’s downgraded our credit ratings (“Debt Rating”).

Our Debt Rating levels could have materially adverse consequences on our business and future prospects and could:

- limit our ability to access debt markets, including for the purpose of refinancing our existing debt;
- cause us to refinance or issue debt with less favorable terms and conditions, which debt may restrict, among other things, our ability to make any dividend distributions or repurchase shares;
- negatively impact current and prospective customers' willingness to transact business with us;
- impose additional insurance, guarantee and collateral requirements;
- limit our access to bank and third-party guarantees, surety bonds and letters of credit; and
- suppliers and financial institutions may lower or eliminate the level of credit provided through payment terms or intraday funding when dealing with us, thereby increasing the need for higher levels of cash on hand, which would decrease our ability to repay indebtedness.

We cannot provide assurance that any of our current Debt Ratings will remain in effect for any given period of time or that a Debt Rating will not be further lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances warrant.

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. 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 their services 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 can be 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, 2015, 48 percent, or 226.8 MMBOE, of our estimated proved reserves were proved undeveloped, and one percent, or 5.1 MMBOE, were proved developed non-producing. In order to develop our proved undeveloped reserves, as of December 31, 2015, we estimate approximately $1.9 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, 2015, we estimate capital expenditures of approximately $10 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, 2015, was estimated using a calculated 12-month average sales price of $2.59 per MMBtu of natural gas (NYMEX Henry Hub spot price), $50.28 per Bbl of oil (NYMEX WTI spot price), and $20.20 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 2015, our monthly average realized natural gas prices, excluding the effect of derivative settlements, were as high as $3.57 per Mcf and as low as $1.91 per Mcf. For the same period, our monthly average realized crude oil prices before the effect of derivative settlements were as high as $54.30 per Bbl and as low as $29.78 per Bbl, and were as high as $18.43 per Bbl and as low as $13.31 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.

Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters.

We regularly sell non-core assets in order to increase capital resources available for core assets and to create organizational and operational efficiencies. We also occasionally sell interests in core assets for the purpose of accelerating the development and increasing efficiencies in other core assets. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the assets or terms we deem acceptable. We at times may be required to retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liabilities or of the indemnification obligations may be difficult to quantify at the time of the transaction and ultimately could be material.

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. In addition, continued low commodity prices may cause third-party service providers to consolidate or declare bankruptcy, which could limit our options for engaging such providers. 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 generally 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. 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 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 will lose our right to develop the related properties. Our total net acreage expiring in the next three years represents approximately 32 percent of our total net undeveloped acreage at December 31, 2015. Although we have identified numerous potential drilling locations, we may not be able to economically drill for and 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, as 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 toward 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 arrangements for crude oil, natural gas, and NGLs. As of December 31, 2015, we were in a net accrued asset position of $488.4 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 continued declines 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 continued declines in crude oil, natural gas, and NGL 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. We do not believe the loss of any single purchaser would materially impact our operating results, as we have numerous options for purchasers in each of our operating regions for our 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. Additionally, the inability of our co-owners to pay joint interest billings could negatively impact our cash flow and financial ability to drill and complete current and future wells.

We have entered into firm transportation contracts that require us to pay fixed sums 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, financial position, and liquidity could be adversely affected.

As of December 31, 2015, we were contractually committed to deliver 2,277 Bcf of natural gas and 36 MMBbl of crude oil, of which the first 1,059 Bcf of natural gas delivered under a certain agreement does not have a deficiency payment. These contracts expire at various dates through 2028. Subsequent to December 31, 2015, we entered into amendments to oil and gas gathering agreements related to certain of our Eagle Ford shale assets, each of which previously did not have a minimum volume commitment. Under these amendments, we are now committed to deliver 310 Bcf of natural gas and 41 MMBbl of oil through 2034. Subsequent to December 31, 2015, we also entered into an amendment to a gas gathering agreement related to certain other Eagle Ford shale assets, which reduced our volume commitment amount as of December 31, 2015, by 829 Bcf. We may enter into additional firm transportation agreements as the 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 expect to develop reserves that will meet or 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, or if we further limit our capital expenditures due to further commodity price declines, the requirements to pay for quantities not delivered could have a material impact on our results of operations, financial position, 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 expense and impairment of unproved properties expense totaling $468.7

million and $78.6 million, respectively, during 2015, $84.5 million and $75.6 million, respectively, during 2014, and $172.6 million and $46.1 million, respectively, during 2013. We also incurred impairment of other property, plant, and equipment expense totaling $49.4 million during 2015. Commodity prices significantly declined in 2014 and 2015. 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 proved reserves, which in turn is impacted by crude oil, natural gas, and NGL prices. The current borrowing base under our credit facility is $2.0 billion. The prices of crude oil, natural gas, and NGLs declined significantly throughout 2015. These declines in prices, or further declines in prices, could limit our borrowing base and reduce the amount we can borrow under our credit facility. Our amendment to our credit facility in 2015 reduced our borrowing base from $2.4 billion to $2.0 billion. This expected reduction was primarily a result of the sale of our Mid-Continent assets in the second quarter of 2015, as well as adjustments consistent with lower commodity prices. Additionally, divestitures of properties or incurrence of additional debt 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, 2015, we had $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 6.125% Senior Notes due 2022 (the "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; $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; and $500.0 million of long-term senior unsecured debt outstanding relating to our 5.625% Senior Notes due 2025 (the "2025 Notes") that we issued on May 21, 2015 (collectively, the 2021 Notes, the 2022 Notes, the 2023 Notes, the 2024 Notes, and the 2025 Notes are referred to as our "Senior Notes"); and $202.0 million of outstanding borrowings under our secured credit facility. We had two outstanding letters of credit in the aggregate amount of $200,000 (which reduce the amount available for borrowing under the facility on a dollar-for-dollar basis), resulting in $1.3 billion of available borrowing capacity under our credit facility, assuming the borrowing conditions under this facility will be met. Our long-term debt represented 58 percent of our total book capitalization as of December 31, 2015.

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 therefrom 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, including induced seismicity 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 in, 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 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 a common practice in the oil and gas industry used to stimulate the 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, the Bakken/Three Forks formations in North Dakota, and the Wolfcamp and Spraberry shale intervals in the Permian Basin. Hydraulic fracturing involves injecting water, sand and certain chemicals under pressure 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 Safe Drinking Water Act (the “SDWA”). The EPA has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. The EPA announced plans to update its chloride water quality criteria for the protection of aquatic life under the federal Water Pollution Control Act (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 2016. 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. On April 7, 2015, the EPA published a proposed rule requiring federal pre-treatment standards for wastewater generated during the hydraulic fracturing process in the Federal Register. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to publicly-owned treatment facilities. The public comment period for the proposed rule ended on July 17, 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. 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

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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 federal governmental agencies are actively involved in studies or reviews that focus on environmental aspects and impacts of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. On June 4, 2015, the EPA issued a draft assessment of potential impacts to drinking water resources from hydraulic fracturing. The draft report did not find widespread impacts to drinking water from hydraulic fracturing. The EPA's inspector general released a report on July 16, 2015 recommending increased EPA oversight of permit issuances as well as the chemicals used in hydraulic fracturing. The United States Department of Energy is also actively involved in research on hydraulic fracturing practices, including groundwater protection.

On March 26, 2015, the Bureau of Land Management ("BLM") published a final rule governing hydraulic fracturing on federal and Indian lands, including private surface lands with underlying federal minerals. The rule was scheduled to become effective on June 24, 2015, but was temporarily stayed by a federal court. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in hydraulic fracturing operations meet certain construction standards, development of appropriate plans for managing flowback water that returns to the surface, heightened standards for interim storage of recovered waste fluids, and submission of detailed information to the BLM regarding the geology, depth and location of pre-existing wells. Although several states, tribes, and industry groups filed several pending lawsuits challenging the rule and the BLM's authority to regulate hydraulic fracturing, the outcome of this litigation is uncertain. If the rule becomes effective, we expect to incur additional costs to comply with such requirements that may be significant in nature, and we could experience delays or even curtailment in the pursuit of hydraulic fracturing activities in certain wells on federal and Indian lands. The rule could also affect drilling units that include both private and federal mineral resources.

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 becomes 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.

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, including damages from induced seismicity, could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to 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.

Requirements to reduce gas flaring could have an adverse effect on our operations.

Wells in the Bakken and Three Forks formations in North Dakota, where we have significant operations, produce natural gas as well as crude oil. Constraints in the current gas gathering and processing network in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In June 2014, the North Dakota Industrial Commission, North Dakota’s chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. The Commission is requiring operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals. The Bureau of Land Management (BLM) has also indicated its intent to pursue a rulemaking related to further controls on the venting and flaring of natural gas on BLM land. A proposed rule has been sent to the White House Office of Management and Budget. These capture requirements, and any similar future obligations in North Dakota or our other locations, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, 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. Pursuant to this commitment, in September 2015, the EPA proposed emission standards for methane and VOC for sources in the oil and gas sector constructed or modified after September 1, 2015. The proposed rules expand the 2012 NSPS for VOC emissions from the oil and gas sector to include methane emissions. For sources not affected by the 2012 NSPS, the proposed rule imposes both VOC and methane standards. In particular, the proposal would require methane reductions from centrifugal and reciprocating compressors, pneumatic pumps, fugitive emissions from well sites and compressor stations and equipment leaks at natural gas processing plants. The proposal does not extend to existing sources and EPA has not indicated when it will propose existing source standards. Additionally, in January 2016, the BLM proposed additional rules designed to reduce methane venting and flaring from production wells, pneumatic controllers and storage tanks on federal and tribal lands, which are expected to be finalized 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,

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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.

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.

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, 2015, to February 17, 2016, the low and high intraday trading prices per share of our common stock as reported by the New York Stock Exchange ranged from a low of $8.38 per share in January 2016 to a high of $60.28 per share in May 2015. 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 17, 2016, 68,037,643 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 520,725 shares of our common stock and 716,129 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 17, 2016, there were 68,077,546 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 Exchange Act.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our business and 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 2015 and 2014, as reported by the New York Stock Exchange:

Quarter Ended	High	Low
December 31, 2015	$42.23	$18.06
September 30, 2015	$45.98	$18.21
June 30, 2015	$60.28	$43.70
March 31, 2015	$53.31	$31.01
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

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2010, and ending on December 31, 2015, 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 17, 2016, the number of record holders of our common stock was 71. Based upon inquiry, management believes that the number of beneficial owners of our common stock is approximately 21,200.

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 each of the years 2005 through 2015. We expect our practice of paying dividends on our common stock to continue, although the payment and amount 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; 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 in amounts not to exceed $0.10 per share of common stock. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $6.8 million and $6.7 million for the years ended December 31, 2015, and December 31, 2014, respectively.

Restricted Shares. We have no restricted shares outstanding as of December 31, 2015, 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, 2015, 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)	Weighted 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, 2015 - March 31, 2015	465	$52.34	—	3,072,184
April 1, 2015 - June 30, 2015	98	$56.22	—	3,072,184
July 1, 2015 - September 30, 2015	186,177	$45.50	—	3,072,184
October 1, 2015 - October 31, 2015	4,988	$35.39	—	3,072,184
November 1, 2015 - November 30, 2015	—	$—	—	3,072,184
December 1, 2015 - December 31, 2015	—	$—	—	3,072,184
Total October 1, 2015 - December 31, 2015	4,988	$35.39	—	3,072,184
Total	191,728	$45.27	—	3,072,184

(1) All shares purchased in 2015 were purchased by us to offset grantee tax withholding obligations that arose 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

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,				
	2015	2014	2013	2012	2011
	(in millions, except per share data)				
Total operating revenues and other income	$1,557.0	$2,522.3	$2,293.4	$1,505.1	$1,603.3
Net income (loss)	$(447.7)	$666.1	$170.9	$(54.2)	$215.4
Net income (loss) per share:					
Basic	$(6.61)	$9.91	$2.57	$(0.83)	$3.38
Diluted	$(6.61)	$9.79	$2.51	$(0.83)	$3.19
Total assets at year-end [1]	$5,621.6	$6,483.1	$4,678.1	$4,179.0	$3,784.0
Long-term debt:					
Revolving credit facility	$202.0	$166.0	$—	$340.0	$—
3.50% Senior Convertible Notes, net of debt discount [1]	$—	$—	$—	$—	$284.7
Senior Notes, net of unamortized deferred financing costs [1]	$2,316.0	$2,166.4	$1,572.9	$1,079.5	$685.4
Cash dividends declared and paid per common share	$0.10	$0.10	$0.10	$0.10	$0.10

[1] Prior period amounts have been reclassified to conform to the current period presentation on the accompanying financial statements. Please refer to the caption Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies for additional discussion of the change in presentation of debt issuance costs on the accompanying balance sheets.

Supplemental Selected Financial and Operations Data

	For the Years Ended December 31,				
	2015	2014	2013	2012	2011
Balance Sheet Data (in millions)					
Total working capital (deficit)	$216.5	$(39.6)	$8.4	$(201.0)	$(42.6)
Total stockholders' equity	$1,852.4	$2,286.7	$1,606.8	$1,414.5	$1,462.9
Weighted-average common shares outstanding (in thousands)					
Basic	67,723	67,230	66,615	65,138	63,755
Diluted	67,723	68,044	67,998	65,138	67,564
Reserves					
Oil (MMBbl)	145.3	169.7	126.6	92.2	71.7
Gas (Bcf)	1,264.0	1,466.5	1,189.3	833.4	664.0
NGLs (MMBbl)	115.4	133.5	103.9	62.3	27.5
MMBOE	471.3	547.7	428.7	293.4	209.9
Production and Operations (in millions)					
Oil, gas, and NGL production revenue	$1,499.9	$2,481.5	$2,199.6	$1,473.9	$1,332.4
Oil, gas, and NGL production expense	$723.6	$715.9	$597.0	$391.9	$290.1
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$921.0	$767.5	$822.9	$727.9	$511.1
General and administrative	$157.7	$167.1	$149.6	$119.8	$118.5
Production Volumes					
Oil (MMBbl)	19.2	16.7	13.9	10.4	8.1
Gas (Bcf)	173.6	152.9	149.3	120.0	100.3
NGLs (MMBbl)	16.1	13.0	9.5	6.1	3.5
MMBOE	64.2	55.1	48.3	36.5	28.3
Realized price					
Oil (per Bbl)	$41.49	$80.97	$91.19	$85.45	$88.23
Gas (per Mcf)	$2.57	$4.58	$3.93	$2.98	$4.32
NGLs (per Bbl)	$15.92	$33.34	$35.95	$37.61	$53.32
Expense per BOE					
Lease operating expense	$3.73	$4.28	$4.49	$4.54	$4.97
Transportation costs	$6.02	$6.11	$5.34	$3.81	$3.05
Production taxes	$1.13	$2.13	$2.19	$2.00	$1.90
Ad valorem tax expense	$0.39	$0.46	$0.33	$0.39	$0.33
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$14.34	$13.92	$17.02	$19.95	$18.07
General and administrative	$2.46	$3.03	$3.09	$3.28	$4.19
Statement of Cash Flow Data (in millions)					
Provided by operating activities	$978.4	$1,456.6	$1,338.5	$922.0	$760.5
Used in investing activities	$(1,144.6)	$(2,478.7)	$(1,192.9)	$(1,457.3)	$(1,264.9)
Provided by financing activities	$166.2	$740.0	$130.7	$422.1	$618.5

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 currently have development positions in the Eagle Ford shale, Bakken/Three Forks and Permian Basin resource plays that are the focus of our capital investment program. We also have a smaller delineation and exploration program in the Powder River Basin. 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, which we believe provide for stable and predictable production and reserves growth.

Our strategic objective is to profitably 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 growth opportunities through both exploration and acquisitions, and we seek to maximize the value of our assets through industry leading technology application and outstanding operational execution. We focus on achieving high full-cycle economic returns on our investments and maintaining a simple, strong balance sheet through a conservative approach to leverage.

In 2015, we had the following financial and operational results:

- We had record annual production for 2015. Our average daily production for 2015 was 52.7 MBbls of oil, 475.7 MMcf of gas, and 44.0 MBbls of NGLs, for an average daily equivalent production rate of 175.9 MBOE, compared with 151.1 MBOE in 2014, an increase of 16 percent year-over-year. Please refer to the caption Production Results below for additional discussion.
- At year-end 2015, we had estimated proved reserves of 471.3 MMBOE, of which 55 percent were liquids (oil and NGLs) and 52 percent were characterized as proved developed. We added 160.6 MMBOE through our drilling program, the majority of which related to our activity in the Eagle Ford shale and the Bakken/Three Forks plays, and acquired 1.2 MMBOE. We had a positive performance revision of 47.3 MMBOE due to improved performance in our Eagle Ford shale and Bakken/Three Forks plays related to enhanced completions and reductions in operating expenses, which extended the economic lives of our wells. This upward revision was offset by a 116.5 MMBOE negative price revision due to the decline in commodity prices in 2015 and 79.4 MMBOE of proved undeveloped reserves removed due to the five-year rule. We divested of 25.4 MMBOE of proved reserves primarily in our Mid-Continent region. Our proved reserve life decreased to 7.3 years in 2015 compared to 9.9 years in 2014. Please refer to Reserves included in Part I, Items 1 and 2 of this report for additional discussion.
- The standardized measure of discounted future net cash flows was $1.9 billion as of December 31, 2015, compared with $5.7 billion as of December 31, 2014. The standardized measure calculation is presented in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report.
- We recorded a net loss of $447.7 million, or $6.61 per diluted share, for the year ended December 31, 2015. This compares with net income of $666.1 million, or $9.79 per diluted share, for the year ended

December 31, 2014. The net loss in 2015 was driven largely by proved and unproved property impairments of $468.7 million and $78.6 million, respectively, as a result of the decline in commodity prices. Please refer to the caption Comparison of Financial Results and Trends between 2015 and 2014 and between 2014 and 2013 below for additional discussion regarding the components of net income (loss).

- We had net cash flow provided by operating activities of $978.4 million for the year ended December 31, 2015, compared with $1.5 billion for the year ended December 31, 2014, which was a decrease of 33 percent year-over-year. Please refer to Analysis of cash flow changes between 2015 and 2014 and between 2014 and 2013 below for additional discussion.
- Adjusted EBITDAX, a non-GAAP financial measure, for the year ended December 31, 2015, was $1.1 billion, compared with $1.6 billion for the same period in 2014. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our net income (loss) and net cash provided by operating activities to adjusted EBITDAX.
- Costs incurred for oil and gas property acquisition, exploration and development activities for the year ended December 31, 2015, totaled $1.4 billion. The majority of our drilling and completion costs incurred during this period were in our Eagle Ford shale and Bakken/Three Forks programs. Please refer to the caption Production Results below for the number of operated wells completed in these programs during 2015. Additionally, we built an inventory of wells drilled during 2015, which we expect to be completed in future years. Total costs incurred for the same period in 2014 totaled $2.7 billion, which included the acquisition of proved and unproved properties in our Gooseneck prospect area and in the Powder River Basin for approximately $561.6 million. Please refer to the caption Costs Incurred in Oil and Gas Producing Activities below for additional discussion.

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, 2015, 2014, and 2013:

	For the Years Ended December 31,		
	2015	2014	2013
Crude Oil (per Bbl):			
Average NYMEX price	$48.68	$93.03	$97.99
Realized price, before the effect of derivative settlements	$41.49	$80.97	$91.19
Effect of derivative settlements	$18.85	$1.71	$(1.27)
Natural Gas:			
Average NYMEX price (per MMBtu)	$2.61	$4.35	$3.73
Realized price, before the effect of derivative settlements (per Mcf)	$2.57	$4.58	$3.93
Effect of derivative settlements (per Mcf) (1)	$0.71	$(0.18)	$0.21
NGLs (per Bbl): (2)			
Average OPIS price	$19.76	$38.93	$40.44
Realized price, before the effect of derivative settlements	$15.92	$33.34	$35.95
Effect of derivative settlements	$1.69	$0.84	$0.71

(1) Natural gas derivative settlements for the years ended December 31, 2015, and 2014, include $15.3 million and $5.6 million, respectively, of early settlements of futures contracts as a result of divesting assets in our Mid-Continent region. These early settlements increased the effect of derivative settlements by $0.09 per Mcf and $0.04 per Mcf for the years ended December 31, 2015, and 2014, respectively.

(2) 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 the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Realized prices 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 continue 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 affects the price of oil. In late 2015, the U.S. lifted its ban on the export of crude oil, which we expect to provide potential for market expansion. Crude oil prices declined throughout 2015 due to slower global economic growth combined with excess global supply. We expect this imbalance between supply and demand to remain for the foreseeable future keeping crude oil prices under downward pressure and at levels below their five-year average. Gas prices also remain under downward pressure as supply exceeds demand, resulting in higher levels of gas in storage compared to the prior year and compared to the five-year average. Excess supply of ethane and propane with higher volumes in storage than historical averages resulted in a further drop in pricing for those products throughout 2015. In response to lower oil, gas, and NGL prices, industry participants significantly cut capital spending in 2015, with additional cuts expected in 2016. We expect the lower capital spending by industry participants to eventually result in a decrease in supply providing upside to commodity pricing for all products.

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 17, 2016, and December 31, 2015:

	As of February 17, 2016	As of December 31, 2015
NYMEX WTI oil (per Bbl)	$37.77	$41.34
NYMEX Henry Hub gas (per MMBtu)	$2.30	$2.53
OPIS NGLs (per Bbl)	$16.12	$17.48

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 partially reduced our exposure to volatility in commodity prices in the near term. Please refer to Note 10 - Derivative Financial Instruments in Part II, Item 8 of this report and the caption titled Commodity Price Risk in Overview of Liquidity and Capital Resources below for additional information regarding our oil, gas, and NGL derivatives.

2015 Operational Activity and Financial Results

Operational Activities. 2015 was a year of transition as the broader oil and gas industry adjusted to lower commodity prices. We scaled back our operated activity during the year by reducing the number of active drilling rigs from 17 to six and deferring the completion of certain drilled wells. The primary focus of our operated drilling activity in 2015 was the development of our Eagle Ford shale and Bakken/Three Forks assets. We realized significant drilling and completion cost reductions during 2015, as our service providers responded to continued commodity price declines. While production declined from quarter to quarter throughout 2015, we had record production for the full-year 2015, driven primarily by the activity in our operated Eagle Ford shale and Bakken/Three Forks development programs.

In our operated Eagle Ford shale program, we began the year operating five drilling rigs and released two rigs throughout the year. Our development program shifted to utilizing longer laterals and completions with higher sand loadings, which resulted in improved well performance. Throughout the year, we tested spacing and the prospectivity of the Upper Eagle Ford on our acreage. As of December 31, 2015, in our operated Eagle Ford shale program, we had 76 gross and net wells that were drilled but not completed.

In our outside-operated Eagle Ford shale program, the operator began 2015 running seven rigs and dropped six rigs throughout the year, exiting the year with one rig in operation.

In our Bakken/Three Forks program, we started the year operating five drilling rigs and released three rigs during the year. We continue to focus most of our activity in Divide County, North Dakota, where we are developing the Bakken and Three Forks intervals and testing completion optimizations and down-spacing. As of December 31, 2015, in our operated Bakken/Three Forks program, we had 48 gross wells (40 net) that were drilled but not completed.

In our Permian program, we started 2015 operating two drilling rigs and released both rigs by mid-year. A large portion of our leasehold position in this region is held by production.

We curtailed activity in our delineation and exploration programs in 2015 to focus on preserving our more prospective acreage. In our Powder River Basin program, we started 2015 operating four drilling rigs and decreased our rig count over 2015, exiting the year with one rig in operation.

Mid-Continent Divestitures. During the second quarter of 2015, we completed the divestiture of our Mid-Continent assets in separate transactions for total cash proceeds received at closing, which reflect the aggregate gross purchase price net of closing adjustments (referred throughout this report as “divestiture proceeds”), of $316.8 million, with a net gain of $108.4 million. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions in Part II, Item 8 of this report for additional information, as this net gain was partially offset by write-downs on certain other assets held for sale and sold during 2015. In conjunction with the divestiture of our Mid-Continent assets, we closed our regional office in Tulsa, Oklahoma.

Production Results. The table below provides a regional breakdown of our production for 2015:

	South Texas & Gulf Coast		Rocky Mountain		Permian		Mid-Continent		Total [1]	
Production:										
Oil (MMBbl)	7.9		9.5		1.8		—		19.2	
Gas (Bcf)	149.5		9.3		5.1		9.7		173.6	
NGLs (MMBbl)	15.7		0.3		—		—		16.1	
Equivalent (MMBOE) [1]	48.5		11.3		2.7		1.7		64.2	
Avg. Daily Equivalents (MBOE/d)	132.9		31.1		7.4		4.6		175.9	
Relative percentage	75	%	18	%	4	%	3	%	100	%

(1) Amounts may not calculate due to rounding.

For the year ended December 31, 2015, we completed 66 gross and net wells in our operated Eagle Ford shale program and 41 gross wells (37 net) in our operated Bakken/Three Forks program. Please refer to Comparison of Financial Results and Trends between 2015 and 2014 and between 2014 and 2013 and A year-to-year overview of selected production and financial information, including trends 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, 2015 (in millions)
Development costs	$ 1,234.1
Exploration costs	132.5
Acquisitions	
Proved properties	10.0
Unproved properties	18.4
Total, including asset retirement obligation [1]	$ 1,395.0

(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.

Costs incurred in oil and gas producing activities, excluding proved and unproved acquisitions, estimated asset retirement obligations, capitalized interest, and support facility allocations, for the year ended December 31, 2015, totaled approximately $1.3 billion and were primarily incurred in the development of our Eagle Ford shale and Bakken/Three Forks programs.

Impairment of Proved and Unproved Properties and Other Property and Equipment. We recorded impairment of proved properties expense of $468.7 million, abandonment and impairment of unproved properties expense of $78.6 million, and impairment of other property and equipment expense of $49.4 million for the year ended December 31, 2015. These impairment expenses were primarily due to continued commodity price declines, as well as our decision to reduce capital spending in our east Texas exploration program in light of the sustained, low commodity price environment. Please refer to Comparison of Financial Results and Trends between 2015 and 2014 and between 2014 and 2013 below for further discussion.

2025 Notes. On May 21, 2015, we issued $500.0 million in aggregate principal amount of our 5.625% Senior Notes, at par, that mature on June 1, 2025. We received net proceeds of $491.0 million from this issuance, which we used for the tender and redemption of the $350.0 million principal amount of our 6.625% Senior Notes due 2019 (the "2019 Notes"), as well as to repay outstanding borrowings under our credit facility and for general corporate purposes. Through these transactions, we extended the first maturity on our Senior Notes to 2021 and reduced our weighted average borrowing rate. Please refer to Note 5 - Long-Term Debt in Part II, Item 8 of this report for additional information.

Revolving Credit Facility. In the third quarter of 2015, our lenders decreased the borrowing base under our credit facility to $2.0 billion from $2.4 billion, primarily a result of the sale of our Mid-Continent assets in the second quarter of 2015, as well as adjustments consistent with lower commodity prices. Please refer to Overview of Liquidity and Capital Resources below for additional discussion of our credit facility.

Outlook for 2016

Our goal is to maintain a strong balance sheet and preserve liquidity in the current commodity price environment. We expect to incur capital expenditures below adjusted EBITDAX in order to minimize any impact to our total debt. We believe this focus on our liquidity will best preserve our balance sheet and will give us the flexibility to adapt as industry conditions change. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our 2016 capital program.

Our capital program for 2016 will be approximately $705 million, of which approximately 85 percent will be invested in drilling and completion activities with the focus on our core development programs in the Bakken/Three Forks, Permian Basin, and Eagle Ford shale. We plan to continue our focus on conducting safe operations even as we pursue cost saving measures throughout our business.

In our operated Eagle Ford shale program, we entered 2016 operating three drilling rigs. We dropped two operated drilling rigs at the start of 2016 and expect to drop the remaining drilling rig during the third quarter. We plan to utilize one frac spread through the third quarter of 2016. We expect to focus the majority of our investment on wells that were drilled but uncompleted at year-end 2015 and to meet lease obligations.

In our outside-operated Eagle Ford shale program, we expect the operator will further slow its pace of development in 2016.

In our operated Bakken/Three Forks program, we entered 2016 operating two drilling rigs. We expect to run a two drilling rig program until the second quarter of 2016, at which time we expect to release one drilling rig and run a one rig program for the remainder of the year.

In our Permian Basin program, we began operating one drilling rig in early 2016 and currently expect to increase to two drilling rigs during the second quarter of 2016. Our focus will be on developing the Wolfcamp and Spraberry shale intervals on our Sweetie Peck property in Upton County, Texas.

We dropped our last operated drilling rig in our Powder River Basin program in mid-February 2016.

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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, 2015, and the immediately preceding three quarters. A detailed discussion follows.

	For the Three Months Ended			
	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015
	(in millions, except for production data)			
Production (MMBOE)	14.9	16.1	16.5	16.8
Oil, gas, and NGL production revenue	$298.7	$366.6	$441.3	$393.3
Oil, gas, and NGL production expense	$169.2	$184.6	$173.7	$196.2
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$240.0	$243.9	$219.7	$217.4
Exploration	$37.9	$19.7	$25.5	$37.4
General and administrative	$33.6	$37.8	$42.6	$43.6
Net income (loss)	$(340.3)	$3.1	$(57.5)	$(53.1)

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics:

	For the Three Months Ended			
	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015
Average net daily production equivalent (MBOE per day)	162.1	174.5	181.0	186.4
Lease operating expense (per BOE)	$3.85	$3.86	$3.26	$3.96
Transportation costs (per BOE)	$6.10	$6.27	$5.64	$6.08
Production taxes as a percent of oil, gas, and NGL production revenue	5.1 %	4.2 %	5.2 %	4.8 %
Ad valorem tax expense (per BOE)	$0.38	$0.40	$0.25	$0.52
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$16.10	$15.19	$13.34	$12.96
General and administrative (per BOE)	$2.26	$2.35	$2.59	$2.60

Note: Amounts may not calculate due to rounding.

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	
	2015	2014	2013	2015/2014	2014/2013	2015/2014	2014/2013
Net production volumes [1]							
Oil (MMBbl)	19.2	16.7	13.9	2.6	2.7	15 %	19 %
Gas (Bcf)	173.6	152.9	149.3	20.7	3.6	14 %	2 %
NGLs (MMBbl)	16.1	13.0	9.5	3.1	3.5	24 %	37 %
Equivalent (MMBOE)	64.2	55.1	48.3	9.1	6.8	16 %	14 %
Average net daily production [1]							
Oil (MBbl per day)	52.7	45.6	38.2	7.0	7.4	15 %	19 %
Gas (MMcf per day)	475.7	419.0	409.2	56.7	9.8	14 %	2 %
NGLs (MBbl per day)	44.0	35.6	26.0	8.4	9.6	24 %	37 %
Equivalent (MBOE per day)	175.9	151.1	132.4	24.9	18.6	16 %	14 %
Oil, gas, and NGL production revenue (in millions)							
Oil production revenue	$797.3	$1,348.3	$1,271.5	$(551.0)	$76.8	(41)%	6 %
Gas production revenue	447.0	699.8	586.3	(252.8)	113.5	(36)%	19 %
NGL production revenue	255.6	433.4	341.8	(177.8)	91.6	(41)%	27 %
Total	$1,499.9	$2,481.5	$2,199.6	$(981.6)	$281.9	(40)%	13 %
Oil, gas, and NGL production expense (in millions)							
Lease operating expense	$239.6	$235.8	$216.9	$3.8	$18.9	2 %	9 %
Transportation costs	386.6	337.1	258.2	49.5	78.9	15 %	31 %
Production taxes	72.4	117.2	105.8	(44.8)	11.4	(38)%	11 %
Ad valorem tax expense	25.0	25.8	16.1	(0.8)	9.7	(3)%	60 %
Total	$723.6	$715.9	$597.0	$7.7	$118.9	1 %	20 %
Realized price							
Oil (per Bbl)	$41.49	$80.97	$91.19	$(39.48)	$(10.22)	(49)%	(11)%
Gas (per Mcf)	$2.57	$4.58	$3.93	$(2.01)	$0.65	(44)%	17 %
NGLs (per Bbl)	$15.92	$33.34	$35.95	$(17.42)	$(2.61)	(52)%	(7)%
Per BOE	$23.36	$45.01	$45.50	$(21.65)	$(0.49)	(48)%	(1)%
Per BOE data [1]							
Production costs:							
Lease operating expense	$3.73	$4.28	$4.49	$(0.55)	$(0.21)	(13)%	(5)%
Transportation costs	$6.02	$6.11	$5.34	$(0.09)	$0.77	(1)%	14 %
Production taxes	$1.13	$2.13	$2.19	$(1.00)	$(0.06)	(47)%	(3)%
Ad valorem tax expense	$0.39	$0.46	$0.33	$(0.07)	$0.13	(15)%	39 %
General and administrative	$2.46	$3.03	$3.09	$(0.57)	$(0.06)	(19)%	(2)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$14.34	$13.92	$17.02	$0.42	$(3.10)	3 %	(18)%
Derivative settlement gain [2][3]	$7.98	$0.22	$0.42	$7.76	$(0.20)	3,527 %	(48)%
Earnings per share information							
Basic net income (loss) per common share	$(6.61)	$9.91	$2.57	$(16.52)	$7.34	(167)%	286 %
Diluted net income (loss) per common share	$(6.61)	$9.79	$2.51	$(16.40)	$7.28	(168)%	290 %
	67,723	67,230	66,615	493	615	1 %	1 %

Basic weighted-average common shares outstanding (in thousands)							
Diluted weighted-average common shares outstanding (in thousands)	67,723	68,044	67,998	(321	) 46	— %	— %

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(1) Amounts and percentage changes may not calculate due to rounding.
(2) 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 year ended December 31, 2013, 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 years ended December 31, 2015, and 2014, are included within the derivative gain line item only.
(3) Natural gas derivative settlements for the years ended December 31, 2015, and 2014, include $15.3 million and $5.6 million, respectively, of early settlements of futures contracts as a result of divesting assets in our Mid-Continent region. These early settlements increased the effect of derivative settlements by $0.09 per Mcf and $0.04 per Mcf for the years ended December 31, 2015, and 2014, respectively.

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, 2015, increased 16 percent compared to the same period in 2014, driven by continued development of our Eagle Ford shale and Bakken/Three Forks programs. We expect production to decrease in 2016 when compared to 2015 as a result of the sale of our Mid-Continent assets during the second quarter of 2015 and reduced drilling and completion activity in late 2015 and throughout 2016 in response to the sustained low commodity price environment. Please refer to Comparison of Financial Results and Trends between 2015 and 2014 and between 2014 and 2013 below for additional discussion.

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, 2015, decreased 48 percent compared to 2014 as a result of significantly lower commodity prices. Our derivative contracts resulted in a $7.98 settlement gain on a per BOE basis for the year ended December 31, 2015.

Lease operating expense ("LOE") on a per BOE basis for the year ended December 31, 2015, decreased 13 percent compared to the same period in 2014. Our LOE is comprised of recurring LOE and workover expense. We experience volatility in our LOE as a result of the impact industry activity has on service provider costs and seasonality in workover expense. Industry activity has significantly decreased in light of the low commodity price environment resulting in service providers lowering costs. For 2016, we expect LOE on a per BOE basis to increase compared with 2015 due to the anticipated decline in year-over-year production exceeding any further decrease in service provider costs.

Transportation costs on a per BOE basis for the year ended December 31, 2015, slightly decreased compared to the same period in 2014. Our Eagle Ford shale assets have meaningfully higher transportation expense per unit of production compared to assets in 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. We expect transportation costs on a per BOE basis to increase in 2016 compared with 2015 as a result of the change in our production mix due to the sale of our Mid-Continent assets in the second quarter of 2015.

Production taxes on a per BOE basis for the year ended December 31, 2015, decreased 47 percent compared to the same period in 2014 driven by the decrease in production revenues, as well as a decrease in our company-wide production tax rate as a result of divesting our Mid-Continent assets in the second quarter of 2015. We generally expect production tax expense to trend with oil, gas, and NGL production revenue on an absolute and per BOE basis. 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 ("G&A") expense on a per BOE basis for the year ended December 31, 2015, decreased 19 percent compared to the same period in 2014 due to a six percent decrease in absolute G&A expense combined with a 16 percent increase in production. The decrease in absolute G&A expense is driven by lower short-term incentive compensation, as well as reduced headcount and overhead cost in the second half of 2015 upon

closing our Tulsa office, partially offset by the $9.3 million of exit and disposal costs incurred related to this closure.
A portion of our G&A 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. In 2016, we expect absolute G&A expense to decrease due to the reduced headcount resulting from the closure of our Tulsa office being in effect for the entire year, as well as other general corporate cost saving initiatives. We expect G&A on a per BOE basis to be relatively flat in 2016 compared with 2015 as we anticipate the reduction in absolute G&A expense to be partially offset by a decrease in production year-over-year.
Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense, for the year ended December 31, 2015, increased three percent, on a per BOE basis, compared to the same period in 2014. Our DD&A rate fluctuates as a result of impairments, planned and closed divestitures, and changes in the mix of our production and the underlying proved reserve volumes. The continued decrease in commodity prices resulted in a decrease in proved reserve volumes and consequently an increased DD&A rate for the last half of 2015. In general, excluding the impact of commodity pricing in recent months, our DD&A rate has decreased over the past several years 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 from 2011 through the first half of 2014 we added reserves with minimal associated costs due to our carry with Mitsui E&P Texas LP ("Mitsui"). Please refer to Note 12 - Acquisition and Development Agreement in Part II, Item 8 of this report for additional discussion on the Mitsui transaction. We expect DD&A expense on a per BOE basis to increase in 2016 in line with the increase that occurred in the last half of 2015 as discussed above, partially offset by reductions in the cost basis to be depleted due to proved properties that were impaired at December 31, 2015. Our DD&A rate will be further impacted should commodity prices further decline in 2016, which could result in lower proved reserves and additional impairments. Please refer to Comparison of Financial Results and Trends between 2015 and 2014 and between 2014 and 2013 for additional discussion.

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, 2015. Consequently, our unvested RSUs and contingent PSUs were anti-dilutive for the year ended December 31, 2015, resulting in a decrease in the diluted weighted-average common shares outstanding for the year ended December 31, 2015, when compared to 2014.

Comparison of Financial Results and Trends between 2015 and 2014 and between 2014 and 2013
Oil, gas, and NGL production
The following table presents the regional changes in our oil, gas, and NGL production, production revenues, and production costs between the years ended December 31, 2015, and 2014:

	Average Net Daily Production Increase (Decrease)		Production Revenue Decrease		Production Costs Increase (Decrease)	
	(MBOE/d)		(in millions)		(in millions)	
South Texas & Gulf Coast	22.8		$(587.8	)	$54.0	
Rocky Mountain	7.2		(230.5	)	(8.2	)
Permian	(0.2	)	(98.8	)	(16.6	)
Mid-Continent [1]	(4.9	)	(64.5	)	(21.5	)
Total	24.9		$(981.6	)	$7.7	

[1] We divested our Mid-Continent assets in the second quarter of 2015.

Our 16 percent increase in equivalent production volumes from 2014 to 2015 is offset by a 48 percent decrease in realized price on a per BOE basis, resulting in a 40 percent decrease in oil, gas, and NGL production revenue between the two periods. Please refer to the caption Oil, gas, and NGL production expense below for discussion on the reasons for the change in production costs from 2014 to 2015.

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

	Average Net Daily Production Increase (Decrease)	Production Revenue Increase (Decrease)	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 from 2013 to 2014 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 from 2013 to 2014 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. Please refer to the caption Oil, gas, and NGL production expense below for discussion on the reasons for the change in production costs from 2013 to 2014.

Please refer to A year-to-year overview of selected production and financial information, including trends above for realized prices received before the effects of derivative settlements for the years ended December 31, 2015, 2014, and 2013, and discussion of trends on a per BOE basis.

Net gain on divestiture activity

The following table presents our net gain on divestiture activity for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Net gain on divestiture activity	$43.0	$0.6	$28.0

The net gain on divestiture activity recorded for the year ended December 31, 2015, is due to the $108.4 million net gain recorded on the sale of our Mid-Continent assets in the second quarter, partially offset by the write-down to fair value of certain other assets held for sale and subsequently divested during 2015.

The minimal net gain on divestiture activity recorded for the year ended December 31, 2014, is due to the $26.9 million gain realized on the sale of non-strategic properties in the Williston Basin in our Rocky Mountain region during the second quarter of 2014, which was mostly offset by write-downs to fair value recorded on other unrelated assets held for sale.

The net gain on divestiture activity recorded for the year ended December 31, 2013, is due to the net gains recorded on the divestitures of certain assets in our Mid-Continent and Rocky Mountain regions of $25.3 million and $13.2 million, respectively, slightly offset by a $7.0 million loss recorded on the divestiture of non-strategic assets in our Permian region.

Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions in Part II, Item 8 of this report for additional discussion.

Marketed gas system revenue and expense

The following table presents our marketed gas system revenue and expense for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Marketed gas system revenue	$9.5	$24.9	$60.0
Marketed gas system expense	$13.9	$24.5	$57.6

Marketed gas system revenue decreased $15.4 million from 2014 to 2015. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $10.5 million from 2014 to 2015. This decrease was due to the sale of our Mid-Continent gas assets in the second quarter of 2015, which eliminated all marketed gas volumes and thus all future marketed gas activity.

Marketed gas system revenue decreased $35.1 million from 2013 to 2014. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $33.2 million from 2013 to 2014. The decrease occurred as a result of the divestiture of our assets in the Anadarko Basin in December 2013.

Other operating revenues

The following table presents our other operating revenues for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Other operating revenues	$4.5	$15.2	$5.8

Other operating revenues for the year ended December 31, 2014, included a $10.7 million gain recorded 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. This settlement gain is the primary cause of the $10.7 million decrease from 2014 to 2015 and the $9.4 million increase from 2013 to 2014, as there was no additional significant other operating revenue activity recorded for the years ended December 31, 2015, 2014, or 2013.

Oil, gas, and NGL production expense

The following table presents our oil, gas, and NGL production expense for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Oil, gas, and NGL production expense	$723.6	$715.9	$597.0

Total production costs increased $7.7 million, or one percent, from 2014 to 2015, primarily due to a 16 percent increase in net equivalent production volumes and a 15 percent increase in transportation expense resulting from the continued development of our Eagle Ford shale program, largely offset by lower service provider costs and decreased production taxes due to lower commodity prices. 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.

Total production costs increased $118.9 million, or 20 percent, from 2013 to 2014 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.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion

The following table presents our DD&A expense for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$921.0	$767.5	$822.9

DD&A expense increased 20 percent in 2015 compared with 2014, primarily due to the increase in production volumes and DD&A rate in 2015, partially offset by our Mid-Continent assets held for sale in the beginning of 2015 and sold in the second quarter. Please refer to the 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.

DD&A expense decreased seven percent in 2014 compared with 2013, primarily due to an 18 percent decrease in the DD&A rate in 2014 driven largely by lower finding and development costs, partially offset by the 14 percent increase in production volumes.

Exploration

The components of exploration expense are summarized as follows:

	For the Years Ended December 31,		
	2015	2014	2013
Summary of Exploration Expense	(in millions)		
Geological and geophysical expenses	$7.5	$11.4	$4.3
Exploratory dry hole	36.6	44.4	5.8
Overhead and other expenses	76.5	74.1	64.0
Total	$120.6	$129.9	$74.1

Exploration expense for 2015 decreased seven percent compared with 2014 mainly due to decreases in exploratory dry hole expense and geological and geophysical (“G&G”) expenses in 2015. During 2015, we expensed one exploratory dry hole in our Rocky Mountain region and three lower cost non-Eagle Ford exploratory dry holes in our South Texas & Gulf Coast region, compared to three higher cost exploratory non-Eagle Ford dry holes expensed 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. During the first quarter of 2014, we performed a seismic study in our Powder River Basin program, which resulted in increased G&G expenses in 2014 compared to 2015 and 2013.

Exploration expense for 2014 increased 75 percent compared with the same period in 2013 mainly due to an increase in exploratory dry hole expense and G&G expense, as discussed above, in addition to higher exploration overhead.

Impairment of proved properties and abandonment and impairment of unproved properties

The following table presents our impairment of proved properties expense and abandonment and impairment of unproved properties expense for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Impairment of proved properties	$468.7	$84.5	$172.6
Abandonment and impairment of unproved properties	$78.6	$75.6	$46.1

Proved and unproved property impairments recorded in 2015 were due to continued commodity price declines, largely impacting our Powder River Basin program and certain legacy and non-core assets, as well as our decision to reduce capital invested in the development of our east Texas exploration program in light of the sustained, low commodity price environment. Commodity prices significantly declined subsequent to the filing date of our September 30, 2015 Quarterly Report on Form 10-Q resulting in additional impairments of proved and unproved properties in the fourth quarter of 2015 totaling $398.8 million. Any amount of future impairments is difficult to predict. If commodity prices remain at levels near those as of January 31, 2016, we would expect to incur impairments in the first quarter of 2016 of up to approximately $250 million. If commodity prices deteriorate further, additional impairments in future periods could occur. In addition to future commodity price declines, changes in drilling plans, downward engineering revisions, or unsuccessful exploration efforts may result in additional proved and unproved property impairments.

Proved and unproved property impairments recorded in 2014 were due to the significant decline in commodity prices in late 2014 resulting in changes in our drilling plans and the abandonment of certain acreage, as well as recognition of the outcomes of exploration and delineation wells in certain prospects in our South Texas & Gulf Coast and Permian regions.

Proved and unproved property impairments recorded in 2013 were 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.

Impairment of other property and equipment

The following table presents our impairment of other property and equipment for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Impairment of other property and equipment	$49.4	$—	$—

We impaired our gas gathering system assets in our east Texas program during the year ended December 31, 2015, in conjunction with the impairment of the associated proved and unproved properties resulting from our decision not to allocate additional capital to the program in light of sustained low commodity prices. We did not record impairments of other property and equipment for the years ended December 31, 2014, or 2013.

General and administrative

The following table presents our general and administrative expense for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
General and administrative	$157.7	$167.1	$149.6

G&A expense decreased $9.4 million, or six percent, from 2014 to 2015 due to lower short-term incentive compensation and reduced headcount and overhead costs resulting from the closing of our Tulsa office in the beginning of the third quarter of 2015. Included in G&A expense for the year ended December 31, 2015, is $9.3 million of exit and disposal costs related to the closure of our Tulsa office. Please refer to the caption A year-to-year overview of selected production and financial information, including trends above for discussion of G&A costs on a per BOE basis.

G&A expense increased $17.6 million from 2013 to 2014 due primarily to an increase in employee headcount during 2014, which resulted in increased base compensation, benefits, and general office expenses.

Change in Net Profits Plan liability

The following table presents the change in our Net Profits Plan liability for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Change in Net Profits Plan liability	$(19.5)	$(29.8)	$(21.8)

This non-cash benefit generally relates to the change in the estimated value of the associated liability between the reporting periods resulting from settlements made or accrued during the period and changes in assumptions used for production rates, reserve quantities, commodity pricing, discount rates, and production costs. The non-cash benefit for 2015 and 2014 is a result of a 72 percent and 52 percent respective decrease in the corresponding liability, which is a result of the continued decline in commodity prices and cash payments made or accrued under the plan. For 2015 and 2014, these cash payments included $3.8 million and $8.3 million, respectively, related to proceeds received from asset divestitures. The non-cash benefit for 2013 is due to cash payments made or accrued under the plan, of which $10.3 million related to divestiture proceeds, slightly offset by an increase in the corresponding liability. We generally expect the change in our Net Profits Plan liability to correlate with fluctuations in commodity prices.

Derivative gain

The following table presents our derivative gain for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Derivative gain	$(408.8)	$(583.3)	$(3.1)

We recognized a derivative gain of $408.8 million for the year ended December 31, 2015, consisting of a $512.6 million gain related to settled contracts, partially offset by a $103.7 million decrease in the fair value of commodity derivative contracts during the period. The decrease in the fair value of commodity derivative contracts is related to the settlement of our 2015 contracts, largely offset by an increase in the fair value of remaining contracts as of December 31, 2015, due to the continued decline in forward commodity strip prices. This compares to a net derivative gain of $583.3 million for the same period in 2014, which consists of a $12.6 million gain on settlements and a $570.7 million increase in the fair value of commodity derivative contracts during the period. Forward commodity strip prices declined at the end of 2014 and continued to decline throughout 2015, resulting in a significant gain on commodity derivative contracts settled in 2015 and a favorable mark-to-market adjustment on our commodity derivative contracts remaining at December 31, 2015.

As noted above, commodity strip pricing declined at the end of 2014, resulting in a significant increase in the fair value of our commodity derivative contracts at December 31, 2014. This compared to a derivative gain of $3.1 million for the year ended December 31, 2013, which consisted 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

The following table presents our other operating expenses for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Other operating expenses	$30.6	$4.7	$30.1

Other operating expenses increased approximately $26.0 million from 2014 to 2015. The increase is primarily due to $13.7 million of expense related to the early termination of drilling rig contracts or fees incurred on rigs placed on standby, $5.3 million of expense related to estimated claims for payment of royalties on certain Federal and Indian leases, as well as a $4.1 million materials inventory write-down during 2015.

Other operating expenses decreased $25.4 million from 2013 to 2014. 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.

Loss on extinguishment of debt

The following table presents our loss on extinguishment of debt for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions)		
Loss on extinguishment of debt	$(16.6)	$—	$—

For the year ended December 31, 2015, we recorded a $16.6 million loss on the early extinguishment of our 2019 Notes, which includes approximately $12.5 million associated with the premium paid for the tender offer and redemption of the notes and approximately $4.1 million for the acceleration of unamortized deferred financing costs. Please refer to Note 5 - Long-Term Debt in Part II, Item 8 of this report for additional information.

Income tax (expense) benefit

The following table presents our income tax (expense) benefit for the periods presented:

	For the Years Ended December 31,		
	2015	2014	2013
	(in millions, except tax rate)		
Income tax (expense) benefit	$275.2	$(398.6)	$(107.7)
Effective tax rate	38.1 %	37.4 %	38.6 %

The increase in the effective tax rate in 2015 compared to 2014 resulted from a tax benefit effect of Oklahoma permanent tax benefits, enacted state rate changes in Texas and North Dakota, and claimed research and development ("R&D") credits added to the benefit created by a pre-tax loss recorded for the year ended December 31, 2015. Please refer to Note 4 - Income Taxes in Part II, Item 8 of this report for further discussion.

The increase in income tax expense for the year ended December 31, 2014, generally trends with the increase in pre-tax net income. The net decrease in the effective tax rate from 2013 to 2014 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.

Overview of Liquidity and Capital Resources

Based on the current commodity price environment, 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 to maintain the flexibility to adjust our activity and capital expenditures in periods of prolonged weak commodity prices or to respond should commodity prices recover.

Sources of cash

We currently expect our 2016 capital program to be primarily funded by cash flows from operations with any remaining cash needs to be funded by borrowings under our credit facility. Although we anticipate that cash flows from these sources will be sufficient to fund our expected 2016 capital program, we may also elect to access the capital markets, depending on prevailing market conditions, as well as divest 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. Our credit ratings were recently downgraded by two major rating agencies. These downgrades and any future downgrades may make it more difficult or expensive for us to borrow additional funds. 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 may be 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. During 2015, cash received from the settlement of commodity derivative contracts provided a significant positive source of cash, which is reflected in net cash provided by operating activities on our consolidated statements of cash flows. The fair value of our commodity derivative contracts was a net asset of $488.4 million at December 31, 2015, of which $367.7 million relates to contracts expected to settle in 2016. As our derivative contracts settle in future periods, and if commodity prices remain at current levels or further decline, our future cash flow from operations will be negatively impacted. 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 currently in place and the timing of settlement of those contracts. There is additional discussion in the referenced note regarding certain commodity derivative contracts restructured subsequent to December 31, 2015, that effectively increased the natural gas volume swaps we have in place in 2017 and eliminated the natural gas volume swaps in place in 2018 and 2019. 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 and our anticipated borrowing base reduction in 2016.
In the second quarter of 2015, we issued $500.0 million in aggregate principal amount of 5.625% Senior Notes due 2025. We used the net proceeds of $491.0 million for the tender and redemption of the $350.0 million principal amount of our 2019 Notes, as well as to repay outstanding borrowings under our credit facility and for general corporate purposes.

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 reductions in available deductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit facility
Our Fifth Amended and Restated Credit Agreement, as amended (the "Credit Agreement") provides a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.5 billion, and a maturity date of December 10, 2019. Our borrowing base is subject to regular semi-annual redeterminations. Effective as of October 7, 2015, our lenders decreased the borrowing base to $2.0 billion from $2.4 billion, which was primarily a result of the sale of our Mid-Continent assets, and adjustments consistent with lower commodity prices. The borrowing base redetermination process under the credit facility considers the value of our proved oil and gas properties and our commodity derivative contracts, as determined by the lender group. We expect an additional reduction in our borrowing base in the first half of 2016 due to the decrease in our proved reserves that we reported as of December 31, 2015, resulting from the continued decline in commodity prices. We do not expect to be negatively impacted by this anticipated borrowing base reduction, as we currently plan to spend within adjusted EBITDAX during 2016 and believe the revised borrowing base amount will be sufficient to meet our anticipated liquidity and operating needs. No individual bank participating in our credit facility represents more than 10 percent of the lender commitments under the credit facility. Borrowings under our credit facility are secured by mortgages on assets having a value equal to at least 75 percent of the total 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 17, 2016, December 31, 2015, and December 31, 2014.

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 December 31, 2015, our debt to EBITDAX ratio and adjusted current ratio were 2.3 and 4.8, respectively. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Our daily weighted-average credit facility debt balance was approximately $253.7 million and $86.6 million for the years ended December 31, 2015, and 2014, respectively. Despite the decrease in our net operating cash flows for the year ended December 31, 2015, resulting from the continued decline in commodity prices, we were able to limit our credit facility borrowings through divestiture proceeds, primarily from the sale of our Mid-Continent assets, and the issuance of our 2025 Notes in the second quarter of 2015. Our daily weighted-average credit facility debt balance was lower throughout 2014 as a result of proceeds received from property divestitures in the fourth quarter of 2013, as well the proceeds from our 2022 Notes being used 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 debt issuances, and the amount of our capital expenditures all impact the amount we have borrowed under our credit facility.

Weighted-average interest rates

Our 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. Our 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, 2015, 2014, and 2013.

	For the Years Ended December 31,					
	2015		2014		2013	
Weighted-average interest rate	6.0	%	6.5	%	6.3	%
Weighted-average borrowing rate	5.5	%	5.9	%	5.7	%

Our weighted-average interest rates and weighted average borrowing rates for the years ended December 31, 2015, 2014, and 2013, have been impacted by the timing of Senior Notes issuances and redemption, the average balance on our revolving credit facility, and the fees paid on the unused portion of our aggregate commitment. The rates disclosed in the above table for the year ended December 31, 2015, do not reflect the approximate $12.5 million premium paid for the tender offer and redemption of the 2019 Notes or the approximate $4.1 million of unamortized deferred financing costs expensed upon extinguishment of these notes during the second quarter of 2015. Please refer to Note 5 - Long-Term Debt in Part II, Item 8 of this report for additional discussion.

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 acquisition, exploration, and development of oil and gas properties are the primary use of our capital resources. During 2015, we spent $1.5 billion in capital expenditures and in acquiring proved and unproved oil and gas properties. These amounts differ from the costs 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 exploration and development 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. Repurchases or exchanges are reviewed as part of the allocation of our capital. During the second quarter of 2015, we conducted a tender offer and redeemed our 2019 Notes. Please refer to Note 5 - Long-Term Debt in Part II, Item 8 of this report for additional discussion.
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 periodically reviews this program as part of the allocation of our capital. During 2015, we did not repurchase any shares of our common stock, and we currently do not plan to repurchase any outstanding shares.
During 2015, we paid $6.8 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. The payment and amount of future dividends remains at the discretion of our Board of Directors.

Analysis of cash flow changes between 2015 and 2014 and between 2014 and 2013

The following tables present changes in cash flows between the years ended December 31, 2015, 2014, and 2013, for our operating, investing, and financing activities. The analysis following each table should be read in conjunction with our consolidated statements of cash flows in Part II, Item 8 of this report.
Operating Activities

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2015	2014	2013	2015/2014	2014/2013	2015/2014	2014/2013
	(in millions)						
Net cash provided by operating activities	$978.4	$1,456.6	$1,338.5	$(478.2)	$118.1	(33)%	9%

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, decreased $366.1 million, or 18 percent, to $1.7 billion for the year ended December 31, 2015, compared with the same period in 2014. Cash paid for LOE increased $22.2 million, or 10 percent, to $252.5 million in 2015 compared with the same period in 2014 due primarily to a 16 percent increase in production volumes, partially offset by a reduction in service provider costs. Cash paid for interest, net of capitalized interest, increased $37.8 million during 2015 compared to 2014 due to making, in 2015, the first interest payment on our 2022 Notes issued at the end of 2014. Additionally, we paid approximately $12.5 million associated with the premium for the tender offer and redemption of the 2019 Notes.

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 to 2013. Cash paid for lease operating expenses in 2014 increased $20.6 million, or nine percent, from 2013. These increases were primarily the result of a 14 percent increase in production volumes. Cash paid for interest, net of capitalized interest, increased $18.4 million during 2014 compared to 2013 due to making, in 2014, the first interest payment on our 2024 Notes issued in 2013. 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

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2015	2014	2013	2015/2014	2014/2013	2015/2014	2014/2013
	(in millions)						
Net cash used in investing activities	$(1,144.6)	$(2,478.7)	$(1,192.9)	$1,334.1	$(1,285.8)	(54)%	108%

Capital expenditures in 2015 decreased $481.2 million, or 24 percent, compared to 2014. Drilling capital incurred decreased approximately 38 percent in 2015 compared to 2014 as a result of reduced operated and non-operated rig count and lower service provider costs. Partially offsetting this decrease in capital activity was our payment, in 2015, of a significant amount of accrued payables at year-end 2014. Additionally, we did not have significant acquisition activity during 2015, whereas we acquired $544.6 million of proved and unproved properties in our Gooseneck prospect area and in the Powder River Basin during 2014. Net proceeds from the sale of oil and gas properties increased $314.1 million in 2015 compared to 2014 due primarily to the divestiture of our remaining Mid-Continent assets during the second quarter of 2015.

Capital expenditures in 2014 increased $421.3 million, or 27 percent, compared to 2013 due primarily to increased spending in our Eagle Ford shale and Bakken/Three Forks programs. As discussed above, we acquired proved and unproved properties in our Gooseneck prospect area and in the Powder River Basin in 2014 that resulted in an increase in acquisition costs of $483.0 million when compared to 2013. Net proceeds from the sale of oil and gas properties in 2014 decreased $381.0 million compared to 2013 due primarily to the sale of our Anadarko Basin assets in the fourth quarter of 2013.

Financing Activities

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2015	2014	2013	2015/2014	2014/2013	2015/2014	2014/2013
	(in millions)						
Net cash provided by financing activities	$166.2	$740.0	$130.7	$(573.8)	$609.3	(78)%	466%

We received $491.0 million of net proceeds from the issuance of our 2025 Notes in the second quarter of 2015. These proceeds were primarily used for the tender and redemption of the principal amount of $350.0 million of our 2019 Notes. See the Operating Activities section above for discussion of the associated premium paid. In 2014, we received $590.0 million of net proceeds from the issuance of our 2022 Notes. We had net borrowings under our credit facility of $36.0 million during the year ended December 31, 2015, compared with net borrowings of $166.0 million in 2014.

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 2014 compared with net payments of $340.0 million during 2013.

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, 2015, our fixed-rate debt and floating-rate debt outstanding totaled $2.35 billion and $202.0 million, respectively. The carrying amount of our floating-rate debt at December 31, 2015, approximates its fair value. Assuming a constant floating-rate debt level of $202.0 million, the before-tax cash flow impact resulting from a 100 basis point change would be $2.0 million over a 12-month period. Please refer to Note 11 - Fair Value Measurements in Part II, Item 8 of this report for additional discussion on the fair value of our Senior Notes.

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 changes in supply and demand and other factors. The markets for oil, gas, and NGLs have been volatile, especially over the last year, 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 2015 production, a 10 percent decrease in our average realized oil, gas, and NGL prices, before the effects of derivative settlements, would have reduced our oil, gas, and NGL production revenues by approximately $79.7 million, $44.7 million, and $25.6 million, respectively.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. 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, 2015, 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 $23 million, $46 million, and $14 million, respectively.

Schedule of Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2015, 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)	$2,552.0	$—	$—	$202.0	$2,350.0
Interest payments (2)	1,101.3	146.9	293.9	285.1	375.4
Delivery commitments (3)	864.0	87.4	242.8	269.1	264.7
Operating leases and contracts (3)	100.4	45.3	16.8	14.9	23.4
Asset retirement obligations (4)	201.0	12.4	45.0	10.8	132.8
Other (5)	47.2	9.2	14.9	13.5	9.6
Total	$4,865.9	$301.2	$613.4	$795.4	$3,155.9

(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, 2015, and assume no future borrowings or repayments 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 throughput commitments.

(4) 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, 2015. 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, 2015, are shown as an obligation in 2016 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.

(5) The majority of the amount shown relates to the unfunded portion of our estimated pension liability of $36.8 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 2016 of $5.8 million. Other amounts include the undiscounted forecasted payments for the Net Profits Plan. 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.

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 2015 or 2014.

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. 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. Please refer to Reserves included in Part I, Items 1 and 2 of this report for additional discussion.

	For the Years Ended December 31,					
	2015		2014		2013	
	MMBOE Change		MMBOE Change		MMBOE Change	
Revisions resulting from performance	47.3		11.3		7.2	
Removal of proved undeveloped reserves no longer in our development plan	(79.4	)	(4.3	)	(2.8	)
Revisions resulting from price changes	(116.5	)	3.4		0.6	
Total	(148.6	)	10.4		5.0	

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,					
	2015		2014		2013	
	MMBOE Change	Percentage Change	MMBOE Change	Percentage Change	MMBOE Change	Percentage Change
10% decrease in SEC pricing	(107.6)	(23)%	(9.6)	(2)%	(9.8)	(2)%
10% decrease in proved undeveloped reserves	(22.7)	(5)%	(26.1)	(5)%	(22.0)	(5)%

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, changes in future service or equipment costs, or related decreases in production taxes or transportation 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, contractual arrangements, 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 $6 million in 2015.

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 cost, estimate the economic lives and timing of abandonment 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.

Impairment of property and equipment. Our property and equipment is recorded at cost. We evaluate a long-lived asset, other than proved and unproved properties, when events or changes in circumstances indicate that its carrying value may be greater than its undiscounted future net cash flows. Impairment, if any, is measured as the excess of an asset's carrying value over its estimated fair value. We use an income valuation technique if there is not a market-observable price for the asset.

Please refer to Impairment of Other Property and Equipment 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 benefit by approximately $7 million for the year ended December 31, 2015.

Accounting Matters

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

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 September 2015, the EPA proposed emission standards for methane and VOC for sources in the oil and gas sector constructed or modified after September 1, 2015. The proposed rules expand the 2012 NSPS for VOC emissions from the oil and gas sector to include methane emissions. For sources not affected by the 2012 NSPS, the proposed rule imposes both VOC and methane standards. In particular, the proposal would require methane reductions from centrifugal and reciprocating compressors, pneumatic pumps, fugitive emissions from well sites and compressor stations and equipment leaks at natural gas processing plants. The proposal does not extend to existing sources and the EPA has not indicated when it will propose existing source standards. Additionally, in January of 2016, the BLM proposed additional rules designed to reduce methane venting and flaring from production wells, pneumatic controllers and storage tanks on federal and tribal lands, which are expected to be finalized in 2016.

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. Pursuant to this commitment, in September of 2015 the EPA proposed emission standards for methane and VOC for sources in the oil and gas sector constructed or modified after September 1, 2015. The proposed rules expand the 2012 NSPS for VOC emissions from the oil and gas sector to include methane emissions. For sources not affected by the 2012 NSPS, the proposed rule imposes both VOC and methane standards. In particular, the proposal would require methane reductions from centrifugal and reciprocating compressors, pneumatic pumps, fugitive emissions from well sites and compressor stations and equipment leaks at natural gas processing plants. The proposal does not extend to existing sources and the EPA has not indicated when it will propose existing source standards. Additionally, in January of 2016, the BLM proposed additional rules designed to reduce methane venting and flaring from production wells, pneumatic controllers and storage tanks on federal and tribal lands, which are expected to be finalized in 2016. In August of 2015, the EPA finalized 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. In February 2016, however, the Supreme Court stayed these rules pending judicial review.

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 45 and 46 percent of our production on a BOE basis in 2015 and 2014, 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 net income (loss) before interest expense, other non-operating income or expense, income taxes, depreciation, depletion, amortization, and accretion expense, exploration expense, impairments, non-cash stock-based 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,		
	2015	2014	2013
	(in thousands)		
Net income (loss) (GAAP)	$(447,710)	$666,051	$170,935
Interest expense	128,149	98,554	89,711
Other non-operating (income) expense, net	(649)	2,561	(67)
Income tax expense (benefit)	(275,151)	398,648	107,676
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	921,009	767,532	822,872
Exploration (1)	113,158	122,577	65,888
Impairment of proved properties	468,679	84,480	172,641
Abandonment and impairment of unproved properties	78,643	75,638	46,105
Impairment of other property and equipment	49,369	—	—
Stock-based compensation expense	27,467	32,694	32,347
Derivative gain	(408,831)	(583,264)	(3,080)
Derivative settlement gain (2)	512,566	12,615	22,062
Change in Net Profits Plan liability	(19,525)	(29,849)	(21,842)
Net gain on divestiture activity	(43,031)	(646)	(27,974)
Loss on extinguishment of debt	16,578	—	—
Other, net	4,054	—	—
Adjusted EBITDAX (Non-GAAP)	1,124,775	1,647,591	1,477,274
Interest expense	(128,149)	(98,554)	(89,711)
Other non-operating income (expense), net	649	(2,561)	67
Income tax (expense) benefit	275,151	(398,648)	(107,676)
Exploration (1)	(113,158)	(122,577)	(65,888)
Exploratory dry hole expense	36,612	44,427	5,846
Amortization of deferred financing costs	7,710	6,146	5,390
Deferred income taxes	(276,722)	397,780	105,555
Plugging and abandonment	(7,496)	(8,796)	(9,946)
Loss on extinguishment of debt	(12,455)	—	—
Other, net	9,707	1,069	2,775
Changes in current assets and liabilities	61,728	(9,302)	14,828
Net cash provided by operating activities (GAAP)	$978,352	$1,456,575	$1,338,514

(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 expense.

(2) Natural gas derivative settlements for the years ended December 31, 2015, and 2014, include a $15.3 million gain and $5.6 million gain on the early settlement of futures contracts during the second quarter of 2015 and first quarter of 2014, respectively, as a result of divesting our Mid-Continent assets.

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, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. 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, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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 and subsidiaries' internal control over financial reporting as of December 31, 2015, 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 24, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
February 24, 2016

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

	December 31, 2015	2014 (as adjusted)
ASSETS		
Current assets:		
Cash and cash equivalents	$18	$120
Accounts receivable (note 2)	134,124	322,630
Derivative asset	367,710	402,668
Prepaid expenses and other	17,137	19,625
Total current assets	518,989	745,043
Property and equipment (successful efforts method):		
Proved oil and gas properties	7,606,405	7,348,436
Less - accumulated depletion, depreciation, and amortization	(3,481,836)	(3,233,012)
Unproved oil and gas properties	284,538	532,498
Wells in progress	387,432	503,734
Oil and gas properties held for sale, net of accumulated depletion, depreciation and amortization of $0 and $22,482, respectively	641	17,891
Other property and equipment, net of accumulated depreciation of $32,956 and $37,079, respectively	153,100	334,356
Total property and equipment, net	4,950,280	5,503,903
Noncurrent assets:		
Derivative asset	120,701	189,540
Other noncurrent assets	31,673	44,659
Total other noncurrent assets	152,374	234,199
Total Assets	$5,621,643	$6,483,145
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 2)	$302,517	$640,684
Derivative liability	8	—
Deferred tax liability	—	142,976
Other current liabilities	—	1,000
Total current liabilities	302,525	784,660
Noncurrent liabilities:		
Revolving credit facility	202,000	166,000
Senior Notes, net of unamortized deferred financing costs (note 5)	2,315,970	2,166,445
Asset retirement obligation	137,525	120,867
Net Profits Plan liability	7,611	27,136
Deferred income taxes	758,279	891,681
Derivative liability	—	70
Other noncurrent liabilities	45,332	39,631
Total noncurrent liabilities	3,466,717	3,411,830
Commitments and contingencies (note 6)		

Stockholders’ equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 68,075,700 and 67,463,060 shares, respectively	681	675
Additional paid-in capital	305,607	283,295
Retained earnings	1,559,515	2,013,997
Accumulated other comprehensive loss	(13,402)	(11,312)
Total stockholders’ equity	1,852,401	2,286,655
Total Liabilities and Stockholders’ Equity	$5,621,643	$6,483,145

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,		
	2015	2014	2013
Operating revenues:			
Oil, gas, and NGL production revenue	$1,499,905	$2,481,544	$2,199,550
Net gain on divestiture activity (note 3)	43,031	646	27,974
Marketed gas system revenue	9,485	24,897	60,039
Other operating revenues	4,544	15,220	5,811
Total operating revenues and other income	1,556,965	2,522,307	2,293,374
Operating expenses:			
Oil, gas, and NGL production expense	723,633	715,878	597,045
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	921,009	767,532	822,872
Exploration	120,569	129,857	74,104
Impairment of proved properties	468,679	84,480	172,641
Abandonment and impairment of unproved properties	78,643	75,638	46,105
Impairment of other property and equipment	49,369	—	—
General and administrative	157,668	167,103	149,551
Change in Net Profits Plan liability	(19,525)	(29,849)	(21,842)
Derivative gain	(408,831)	(583,264)	(3,080)
Marketed gas system expense	13,922	24,460	57,647
Other operating expenses	30,612	4,658	30,076
Total operating expenses	2,135,748	1,356,493	1,925,119
Income (loss) from operations	(578,783)	1,165,814	368,255
Non-operating income (expense):			
Other, net	649	(2,561)	67
Interest expense	(128,149)	(98,554)	(89,711)
Loss on extinguishment of debt	(16,578)	—	—
Income (loss) before income taxes	(722,861)	1,064,699	278,611
Income tax (expense) benefit	275,151	(398,648)	(107,676)
Net income (loss)	$(447,710)	$666,051	$170,935
Basic weighted-average common shares outstanding	67,723	67,230	66,615
Diluted weighted-average common shares outstanding	67,723	68,044	67,998
Basic net income (loss) per common share	$(6.61)	$9.91	$2.57
Diluted net income (loss) per common share	$(6.61)	$9.79	$2.51

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, 2015	2014	2013
Net income (loss)	$(447,710)	$666,051	$170,935
Other comprehensive income (loss), net of tax:			
Reclassification to earnings [1]	—	—	1,115
Pension liability adjustment [2]	(2,090)	(5,896)	2,483
Total other comprehensive income (loss), net of tax	(2,090)	(5,896)	3,598
Total comprehensive income (loss)	$(449,800)	$660,155	$174,533

(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, 2013	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 of RSUs and settlement of PSUs, net of shares used for tax withholdings	526,852	5	(16,225)	—	—	—	—	(16,220)
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 loss	—	—	—	—	—	—	(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
Net loss	—	—	—	—	—	(447,710)	—	(447,710)
Other comprehensive loss	—	—	—	—	—	—	(2,090)	(2,090)
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,772)	—	(6,772)
Issuance of common stock under Employee Stock Purchase Plan	197,214	2	4,842	—	—	—	—	4,844
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	375,523	4	(8,682)	—	—	—	—	(8,678)
Stock-based compensation expense	39,903	—	27,467	—	—	—	—	27,467
Other income tax expense	—	—	(1,315)	—	—	—	—	(1,315)
Balances, December 31, 2015	68,075,700	$681	$305,607	—	$—	$1,559,515	$ (13,402)	$1,852,401

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, 2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$(447,710)	666,051	170,935
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Net gain on divestiture activity	(43,031)	(646)	(27,974)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	921,009	767,532	822,872
Exploratory dry hole expense	36,612	44,427	5,846
Impairment of proved properties	468,679	84,480	172,641
Abandonment and impairment of unproved properties	78,643	75,638	46,105
Impairment of other property and equipment	49,369	—	—
Stock-based compensation expense	27,467	32,694	32,347
Change in Net Profits Plan liability	(19,525)	(29,849)	(21,842)
Derivative gain	(408,831)	(583,264)	(3,080)
Derivative settlement gain	512,566	12,615	22,062
Amortization of deferred financing costs	7,710	6,146	5,390
Non-cash loss on extinguishment of debt	4,123	—	—
Deferred income taxes	(276,722)	397,780	105,555
Plugging and abandonment	(7,496)	(8,796)	(9,946)
Other, net	13,761	1,069	2,775
Changes in current assets and liabilities:			
Accounts receivable	140,200	24,088	(79,398)
Prepaid expenses and other	2,563	(1,822)	98
Accounts payable and accrued expenses	(86,267)	9,466	91,516
Accrued derivative settlements	5,232	(41,034)	2,612
Net cash provided by operating activities	978,352	1,456,575	1,338,514
Cash flows from investing activities:			
Net proceeds from the sale of oil and gas properties	357,938	43,858	424,849
Capital expenditures	(1,493,608)	(1,974,798)	(1,553,536)
Acquisition of proved and unproved oil and gas properties	(7,984)	(544,553)	(61,603)
Other, net	(985)	(3,256)	(2,613)
Net cash used in investing activities	(1,144,639)	(2,478,749)	(1,192,903)
Cash flows from financing activities:			
Proceeds from credit facility	1,872,500	1,285,500	1,203,000
Repayment of credit facility	(1,836,500)	(1,119,500)	(1,543,000)
Debt issuance costs related to credit facility	—	(3,388)	(3,444)
Net proceeds from Senior Notes	490,951	589,991	490,185
Repayment of Senior Notes	(350,000)	—	—
Proceeds from sale of common stock	4,844	4,877	6,858
Dividends paid	(6,772)	(6,723)	(6,663)
Net share settlement from issuance of stock awards	(8,678)	(10,624)	(16,220)
Other, net	(160)	(87)	(5)

Net cash provided by financing activities	166,185	740,046	130,711
Net change in cash and cash equivalents	(102)	(282,128)	276,322
Cash and cash equivalents at beginning of period	120	282,248	5,926
Cash and cash equivalents at end of period	$18	$120	$282,248

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,		
	2015	2014	2013
	(in thousands)		
Cash paid for interest, net of capitalized interest	$126,988	$89,145	$70,702
Net cash paid (refunded) for income taxes	$1,630	$1,936	$(204)

As of December 31, 2015, 2014, and 2013, $97.4 million, $357.2 million, and $217.8 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 net cash used in investing activities in the periods during which the payables are settled.

During the second quarter of 2014 and the third quarter of 2013, the Company exchanged properties in its Rocky Mountain region with fair values of $6.2 million and $25.0 million, respectively. The amount of cash consideration paid 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, 2015, 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. Please refer to the caption Recently Issued Accounting Standards below for additional discussion of the change in presentation of debt issuance costs on the accompanying balance sheets.
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, and asset retirement obligations, 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.
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. The Company's allowance for doubtful accounts as of December 31, 2015, totaled $1.1 million, primarily for receivables from joint interest owners. The Company had no allowance for doubtful accounts as of December 31, 2014.

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 2015 and 2014, the Company had one major customer, which represented approximately 21 percent and 19 percent, respectively, of total production revenue, which is discussed in the next paragraph. During 2015 and 2014, the Company also sold to four entities that are under common ownership. In aggregate, these four entities represented approximately 10 percent and 14 percent of total production revenue in 2015 and 2014, respectively; however, none of these entities individually represented more than 10 percent of total production revenue. Additionally, in 2015 the Company sold to three entities that are under common ownership, which in aggregate represented 11 percent of its total production revenue; however, none of these entities individually represented more than 10 percent of the Company's total production revenue. During 2013, the Company had three major customers, which represented approximately 26 percent, 16 percent, and 12 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 throughput commitments for up to 10 years pursuant to each contract. While the Company's joint venture partner is the first purchaser under these contracts, representing 21 percent and 19 percent of total production revenue in 2015 and 2014, respectively, 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 from other operated areas.

The Company's policy is to use the commodity affiliates of the lenders under its credit facility as its derivative counterparties, and each counterparty must have investment grade senior unsecured debt ratings. Each of the Company's 10 counterparties meet both of these requirements as of the filing date of this report.

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, 2015, and 2014, the estimated salvage value of the Company's equipment was $29.7 million and $50.8 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 carrying value or fair value less the cost to sell. For additional discussion on assets held for sale, please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions.

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, 2015, and 2014, the Company has capitalized approximately $44.0 million and $35.0 million, respectively, related to the development and implementation of accounting and operational software.

Derivative Financial Instruments
The Company seeks to manage or reduce commodity price risk on its 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 drilled 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, contractual agreements, 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 reserves and risk adjusted 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 $468.7 million, $84.5 million, and $172.6 million, of proved property impairment expense for the years ended December 31, 2015, 2014, and 2013, respectively. The impairments of proved properties in 2015 were due to continued commodity price declines, largely impacting the Company's Powder River Basin program and certain legacy and non-core assets in the Rocky Mountain region, as well as the Company's decision to reduce capital invested in the development of its east Texas exploration program in its South Texas & Gulf Coast region. The impairments of proved properties in 2014 were primarily 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 primarily 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.

For the years ended December 31, 2015, 2014, and 2013, the Company recorded expense related to the abandonment and impairment of unproved properties of $78.6 million, $75.6 million, and $46.1 million, respectively. The Company's abandonment and impairment of unproved properties expense in 2015 and 2014 was primarily a result of lease expirations and acreage the Company no longer intended to develop in light of changes in drilling plans in response to the continued 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.

Impairment of Other Property and Equipment

A long-lived asset is evaluated for potential impairment whenever events or changes in circumstances indicate that its carrying value may be greater than its undiscounted future net cash flows. Impairment, if any, is measured as the excess of an asset's carrying value over its estimated fair value. The Company uses an income valuation technique if there is not a market-observable price for the asset.

For the year ended December 31, 2015, the Company recorded a $49.4 million impairment charge on its gas gathering system assets in east Texas, in conjunction with the impairment of the associated proved and unproved properties, resulting from the Company's decision to reduce capital spent in the program in light of sustained, low commodity prices. The Company did not have any impairments of other property and equipment for the years ended December 31, 2014, or 2013.

Sales of Proved and Unproved Properties

The partial sale of proved property within an existing field is accounted for as normal retirement and no net 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 net 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 net gain on divestiture activity is recognized to the extent that the sales price exceeds the carrying amount of the unproved property. A net 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 – Divestitures, Assets Held for Sale, and Acquisitions.

Stock-Based Compensation

At December 31, 2015, 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, and included within general and administrative expense and exploration expense in the accompanying statements of operations.

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 unvested RSUs, contingent PSUs, and in-the-money outstanding stock options. When there is a loss from continuing operations, as was the case for the year ended December 31, 2015, 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 Plan.

The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, and in-the-money stock options. All remaining stock options were exercised during the year ended December 31, 2014.

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

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Dilutive	—	814	1,383
Anti-dilutive	256	—	—

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

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands, except per share amounts)		
Net income (loss)	$(447,710)	$666,051	$170,935
Basic weighted-average common shares outstanding	67,723	67,230	66,615
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs (1)	—	814	1,383
Diluted weighted-average common shares outstanding	67,723	68,044	67,998
Basic net income (loss) per common share	$(6.61)	$9.91	$2.57
Diluted net income (loss) per common share	$(6.61)	$9.79	$2.51

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(1) For the year ended December 31, 2015, the shares 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 [1]	Pension Liability Adjustments
	(in thousands)	
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)
For the year ended December 31, 2015		
Net actuarial loss		$(4,990)
Reclassification to earnings	$—	1,853
Tax benefit	—	1,047
Loss, net of tax	$—	$(2,090)

(1) As of December 31, 2013, all commodity derivative contracts that had been previously designated as cash flow hedges had settled and had been reclassified into earnings from AOCL.

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 $202.0 million of outstanding loans under its credit facility as of December 31, 2015. The Company had $166.0 million of outstanding loans under its credit facility as of December 31, 2014. The Company's Senior Notes are recorded at cost, net of unamortized deferred financing costs, 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 within the United States. The Company reports as a single industry segment. The Company sold its Mid-Continent assets in 2015, and therefore, no longer has marketed gas volumes as of December 31, 2015. Prior to the sale of these assets, the Company's gas marketing function provided mostly internal services and acted as the first purchaser of natural gas and natural gas liquids produced by the Company in certain cases. The Company considered its marketing function as ancillary to its oil and gas producing activities. The amount of income these operations generated from marketing gas produced by third parties was not material to the Company's results of operations, and segmentation of such activity would not have provided a better understanding of the Company's performance. However, gross revenue and expense related to marketing activities for gas produced by third parties is 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 2015 or 2014.

Recently Issued Accounting Standards

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 full retrospective method or a modified retrospective method, as outlined in the guidance. In August 2015, the FASB deferred the effective date of the new revenue recognition standard by one year. The revenue recognition standard is now effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted but only for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. 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.

Effective January 1, 2015, the Company adopted, on a prospective basis, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2015-01, "Income Statement – Extraordinary and Unusual Items." This ASU simplifies income statement presentation by eliminating the concept of extraordinary items. There was no impact to the Company's financial statements or disclosures from the adoption of this standard.

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 full 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.

Effective November 1, 2015, the Company early adopted, on a retrospective basis, FASB ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs" ("ASU 2015-03"). ASU 2015-03 requires deferred financing costs to be presented on the accompanying balance sheets as a direct deduction from the carrying value of the related debt liability. In accordance, the Company has reclassified $33.6 million of deferred financing costs related to its Senior Notes at December 31, 2014, from the other noncurrent assets line item to the Senior Notes, net of unamortized deferred financing costs line item. The December 31, 2014, accompanying balance sheet line items that were adjusted as a result of the adoption of ASU 2015-03 are presented in the following table:

	As of December 31, 2014	
	As Reported	As Adjusted
	(in thousands)	
Other noncurrent assets	$78,214	$44,659
Total other noncurrent assets	$267,754	$234,199
Total Assets	$6,516,700	$6,483,145
Senior Notes	$2,200,000	N/A
Senior Notes, net of unamortized deferred financing costs	N/A	$2,166,445
Total noncurrent liabilities	$3,445,385	$3,411,830
Total Liabilities and Stockholders' Equity	$6,516,700	$6,483,145

ASU 2015-03 does not specifically address the accounting for deferred financing costs related to line-of-credit arrangements. In August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements" ("ASU 2015-15") allowing for deferred financing costs associated with line-of-credit arrangements to continue to be presented as assets. ASU 2015-15 is consistent with how the Company currently accounts for deferred financing costs related to the Company's revolving credit facility.

Effective December 1, 2015, the Company early adopted, on a prospective basis, FASB ASU No. 2015-17, "Balance Sheet Classification of Deferred Taxes" ("ASU 2015-17"). ASU 2015-17 requires that deferred tax liabilities and assets, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by the amendments in ASU 2015-17. As ASU 2015-17 was adopted on a prospective basis, the Company did not retrospectively adjust prior periods.

There are no other accounting standards applicable to the Company that would have a material effect on the Company's financial statements and disclosures that have been issued but not yet adopted by the Company as of December 31, 2015, 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,	
	2015	2014
	(in thousands)	
Accrued oil, gas, and NGL production revenue	$58,256	$180,250
Amounts due from joint interest owners	22,269	58,347
Accrued derivative settlements	34,579	39,811
State severance tax refunds	12,072	24,394
Other	6,948	19,828
Total accounts receivable	$134,124	$322,630

Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2015	2014
	(in thousands)	
Accrued capital expenditures	$97,355	$357,156
Revenue and severance tax payable	44,387	63,779
Accrued lease operating expense	21,943	34,822
Accrued property taxes	14,078	15,059
Accrued compensation	41,154	56,279
Accrued interest	34,378	40,786
Other	49,222	72,803
Total accounts payable and accrued expenses	$302,517	$640,684

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

2015 Divestiture Activity

- Mid-Continent Divestiture. During the second quarter of 2015, the Company divested its Mid-Continent assets in multiple transactions for total divestiture proceeds of $316.8 million and a final net gain of $108.4 million. Certain of these assets were written down by $30.0 million to reflect fair value less estimated costs to sell upon reclassification to assets held for sale as of March 31, 2015. This write-down is reflected in the final net gain of $108.4 million discussed above.

In conjunction with the divestiture of its Mid-Continent assets, the Company closed its Tulsa, Oklahoma office. For the year ended December 31, 2015, the Company recorded $9.3 million of exit and disposal costs, the majority of which were recorded as general and administrative expense in the accompanying statements of operations. Additionally, during the third quarter of 2015, the Company vacated its office space in Tulsa. The Company has subleased the space for a portion of the remaining term. As of December 31, 2015, the Company is obligated to pay lease costs of approximately $4.0 million, net of expected income from office space currently subleased, which will be expensed over the duration of the lease, which expires in 2022. This obligation will decrease if the Company successfully subleases space for additional terms.

- Permian Divestiture. During the fourth quarter of 2015, the Company divested certain non-core assets in its Permian region. Total divestiture proceeds were $25.1 million and the estimated total net gain on this divestiture was $2.4 million. This divestiture is subject to normal post-closing adjustments, which are expected to occur in the first half of 2016.

Write-downs on certain other assets held for sale and subsequently sold during the year ended December 31, 2015, totaled $68.6 million. Write-downs on assets held for sale are reflected as a loss on divestiture activity which is included in the net gain on divestiture activity line item in the accompanying statements of operations. Please refer to Assets Held for Sale below for further discussion.

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 net 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 offset the net gain on the Rocky Mountain divestiture discussed above.

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 final 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 divestiture proceeds 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.

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. Any subsequent decreases to the estimated fair value less costs to sell impact the measurement of assets held for sale.

As of December 31, 2015, the accompanying balance sheets present $641,000 of assets held for sale. There is a corresponding asset retirement obligation liability of $241,000 for assets held for sale included in the asset retirement obligation financial statement line item. Certain assets classified as held for sale and subsequently sold during 2015 were written down to fair value less estimated costs to sell, as discussed above.

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

2015 Acquisition Activity

There was no significant acquisition activity during the year ended December 31, 2015.

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 after final closing adjustments was $321.8 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.

The Company 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 final 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. Refer to Note 11 – Fair Value Measurements for additional discussion on the valuation techniques used in determining the fair value of acquired properties.

	Acquisition #1 As of September 24, 2014		Acquisition #2 As of October 15, 2014	
Purchase Price	(in thousands)			
Cash consideration	$321,807		$84,836	
Fair value of assets and liabilities acquired:				
Proved oil and gas properties	$203,467		$54,612	
Unproved oil and gas properties	126,588		29,610	
Total fair value of oil and gas properties acquired	330,055		84,222	
Working capital	(6,135	)	2,232	
Asset retirement obligation	(2,113	)	(1,618	)
Total fair value of net assets acquired	$321,807		$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, primarily in the Powder River Basin, in multiple transactions for approximately $135.5 million in total cash consideration after final closing adjustments, plus approximately 7,000 net acres of non-core assets in the Company's Rocky Mountain region.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Current portion of income tax expense			
Federal	$—	$—	$—
State	1,571	868	2,121
Deferred portion of income tax expense (benefit)	(276,722)	397,780	105,555
Total income tax expense (benefit)	$(275,151)	$398,648	$107,676
Effective tax rate	38.1%	37.4%	38.6%

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

	As of December 31,	
	2015	2014
	(in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$854,029	$1,029,424
Derivative asset	179,543	220,437
Other	1,233	4,475
Total deferred tax liabilities	1,034,805	1,254,336
Deferred tax assets:		
Federal and state tax net operating loss carryovers	244,942	184,447
Stock compensation	14,529	16,763
Other liabilities	27,449	25,715
Total deferred tax assets	286,920	226,925
Valuation allowance	(10,394)	(7,246)
Net deferred tax assets	276,526	219,679
Total net deferred tax liabilities [(1)]	$758,279	$1,034,657
Current federal income tax refundable	$5,378	$4,734
Current state income tax refundable	$65	$—
Current state income tax payable	$—	$25

(1) All deferred tax liabilities and assets as of December 31, 2015, are classified as noncurrent on the accompanying balance sheets upon the Company's adoption of ASU 2015-17 on a prospective basis. Prior year amounts have not been restated. Please refer to the caption Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies for additional discussion.

At December 31, 2015, the Company estimated its federal net operating loss carryforward at $796.7 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 $338.9 million that expire between 2016 and 2036 and it has federal R&D credit carryforwards of $7.2 million that expire between 2028 and 2033. 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 2014 to 2015 primarily reflects an allocable change to the Company's mix of state apportioned losses and the anticipated utilization of state cumulative 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, R&D credits, and other permanent differences, as follows:

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Federal statutory tax expense (benefit)	$(253,001)	$372,644	$97,514
Increase (decrease) in tax resulting from:			
State tax expense (benefit) (net of federal benefit)	(21,583)	21,350	9,400
Change in valuation allowance	3,148	2,245	(314)
Research and development credit	(1,971)	—	—
Other	(1,744)	2,409	1,076
Income tax expense (benefit)	$(275,151)	$398,648	$107,676

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. During the first quarter of 2015, as a result of its R&D credit settlement with the IRS Appeals Office in late 2014, the Company recorded an additional $2.0 million net R&D credit from a claim filed on an amended return. At December 31, 2015, the Company's 2007 - 2011 IRS examination was still ongoing, but a final agreement was reached in January 2016. There are no material adjustments to previously recorded amounts. During the quarter ended September 30, 2015, the IRS initiated an audit of the SM-Mitsui Tax Partnership for the 2013 tax year. The Company has a significant investment in the underlying assets of the tax partnership and this audit was still in progress at December 31, 2015.

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, 2015, the Company estimates the range of reasonably possible change in 2016 to the recorded unrecognized tax benefits presented in the table below could be from zero to $1.8 million.

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

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Beginning balance	$1,582	$2,358	$2,278
Additions for tax positions of prior years	1,200	140	80
Settlements	—	(916)	—
Ending balance	$2,782	$1,582	$2,358

Note 5 – Long-Term Debt
Revolving Credit Facility
The Company's Fifth Amended and Restated Credit Agreement, as amended, provides 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. Effective as of October 7, 2015, the Company's lenders decreased the borrowing base to \$2.0 billion as part of the regularly scheduled semi-annual redetermination under the Credit Agreement. This expected reduction from \$2.4 billion was primarily a result of the Company's sale of its Mid-Continent assets, plus adjustments consistent with lower commodity prices. There was no change in the current aggregate lender commitments of \$1.5 billion. The next redetermination date is scheduled for April 1, 2016. The borrowing base redetermination process under the credit facility considers the value of the Company's proved oil and gas properties and commodity derivative contracts, as determined by the lender group. Borrowings under the facility are secured by mortgages on assets having a value equal to at least 75 percent of the total 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 the Credit Agreement, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to adjusted EBITDAX, as defined by the 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 Credit Agreement, of no less than 1.0. The Company was in compliance with all financial and non-financial covenants under the Credit Agreement as of December 31, 2015, 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 Credit Agreement as of February 17, 2016, December 31, 2015, and December 31, 2014:

	As of February 17, 2016	As of December 31, 2015	As of December 31, 2014
	(in thousands)		
Credit facility balance [1]	\$243,000	\$202,000	\$166,000
Letters of credit [2]	\$200	\$200	\$808
Available borrowing capacity	\$1,256,800	\$1,297,800	\$1,333,192

(1) Deferred financing costs attributable to the credit facility are presented as a component of other noncurrent assets on the accompanying balance sheets and thus are not deducted from the credit facility balance.
(2) Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis.

Senior Notes

The Senior Notes, net of unamortized deferred financing costs, line on the accompanying balance sheets as of December 31, 2015, and 2014, consisted of the following:

	As of December 31,					
	2015			2014 [1]		
	Senior Notes	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs	Senior Notes	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.625% Notes due 2019	$—	$—	$—	$350,000	$4,591	$345,409
6.50% Notes due 2021	350,000	4,106	345,894	350,000	4,806	345,194
6.125% Notes due 2022	600,000	8,714	591,286	600,000	9,812	590,188
6.50% Notes due 2023	400,000	5,231	394,769	400,000	5,969	394,031
5.0% Notes due 2024	500,000	7,455	492,545	500,000	8,377	491,623
5.625% Notes due 2025	500,000	8,524	491,476	—	—	—
Total	$2,350,000	$34,030	$2,315,970	$2,200,000	$33,555	$2,166,445

(1) Prior period amounts have been reclassified to conform to the current period presentation on the accompanying balance sheets. Please refer to the section Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies for additional discussion.

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 indentures governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; however, 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, 2015, and through the filing date of this report. All Senior Notes are registered under the Securities Act as of December 31, 2015. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices based on a make-whole amount plus accrued and unpaid interest as described in the indentures governing the notes.

2019 Notes

On May 7, 2015, the Company commenced a cash tender offer for any and all of its outstanding 6.625% Senior Notes due 2019 at a price of $1,036.88 per $1,000 of principal amount for all 2019 Notes tendered by May 20, 2015 ("Consent Payment Deadline"), and at a price of $1,006.88 per $1,000 of principal amount for all 2019 Notes properly tendered thereafter. On the Consent Payment Deadline, the Company received tenders and consents from the holders of approximately $242.9 million in aggregate principal amount, or approximately 69 percent, of its outstanding 2019 Notes in connection with the cash tender offer. Following its entry into the supplemental indenture dated as of May 21, 2015, to the indenture dated as of February 7, 2011, between the Company and U.S. Bank National Association, as Trustee, the Company accepted the 2019 Notes tendered as of the Consent Payment Deadline in exchange for payment of total consideration, including accrued interest, of approximately $256.2 million under the Tender Offer and Consent Solicitation. On June 5, 2015, the Company accepted $1.5 million of 2019 Notes tendered after the Consent Payment Deadline in exchange for payment of total consideration, including accrued interest, of approximately $1.6 million.

On June 22, 2015, the Company redeemed the remaining outstanding 2019 Notes at a redemption price of 103.313% of the principal amount for payment of total consideration, including accrued interest, of approximately $111.5 million.

The Company recorded a loss on extinguishment of debt related to the tender offer and redemption of its 2019 Notes of approximately $16.6 million for the quarter ended June 30, 2015. This amount includes approximately $12.5 million associated with the premium paid for the tender offer and redemption of the 2019 Notes and approximately $4.1 million related to the acceleration of unamortized deferred financing costs.

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.

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.

On November 17, 2014, the Company entered into a registration rights agreement that provided holders of the 2022 Notes certain registration rights under the Securities Act. The Company closed its offer to exchange its 2022 Notes for notes registered under the Securities Act on July 10, 2015.

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.

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.

2025 Notes

On May 21, 2015, the Company issued $500.0 million in aggregate principal amount of 5.625% Senior Notes due 2025. The 2025 Notes were issued at par and mature on June 1, 2025. The Company received net proceeds of $491.0 million after deducting fees of $9.0 million, which are being amortized as deferred financing costs over the life of the 2025 Notes. The net proceeds were used to fund the consideration paid to the tendering holders of the 2019 Notes and to redeem the remaining untendered 2019 Notes, as well as repay outstanding borrowings under the Credit Agreement and for general corporate purposes.

Capitalized Interest

Capitalized interest costs for the Company for the years ended December 31, 2015, 2014, and 2013, were $25.1 million, $16.2 million, and $11.0 million, respectively.

Note 6 – Commitments and Contingencies

Commitments

The Company has entered into various agreements, which include drilling rig contracts of $35.3 million, gathering, processing, and transportation throughput commitments of $864.0 million, office leases, including maintenance, of $59.4 million, and other miscellaneous contracts and leases of $5.7 million. The annual minimum payments for the next five years and total minimum payments thereafter are presented below:

Years Ending December 31,	Amount [(1)] (in thousands)
2016	$132,747
2017	128,074
2018	131,489
2019	142,161
2020	141,854
Thereafter	288,113
Total	$964,438

(1) During the third quarter of 2015, the Company vacated its office space in Tulsa, Oklahoma. These amounts include lease payments for the Tulsa office, net of sublease income. The Company expects to receive $3.5 million of sublease income as follows: $831,000 in 2016, $953,000 in 2017, $978,000 in 2018, and $741,000 in 2019.

Drilling rig contracts

The Company has multiple long-term drilling rig contracts. Early termination of these rig contracts as of December 31, 2015, would result in termination penalties of $26.0 million, which would be in lieu of paying the remaining drilling commitments of $35.3 million included in the table above. In light of the low commodity price environment, the Company curtailed drilling activity during 2015. For the year ended December 31, 2015, the Company incurred $13.7 million of expense related to the early termination of drilling rig contracts or fees incurred on rigs placed on standby, which are recorded in the other operating expenses line item in the accompanying statements of operations. These fees include the costs to terminate the contract for an operated drilling rig in the Company’s South Texas & Gulf Coast region, in early 2016.

Subsequent to December 31, 2015, the Company renegotiated the terms of certain drilling rig contracts to provide increased flexibility with regard to the timing of activity and payment.

Transportation commitments

The Company has gathering, processing, and transportation throughput commitments with various third parties that require delivery of a minimum amount of 2,277 Bcf of natural gas and 36 MMBbl of crude oil, of which the first 1,059 Bcf of natural gas delivered under a certain agreement does not have a deficiency payment. These contracts expire at various dates through 2028. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments under certain agreements. As of December 31, 2015, if the Company delivers no product, the aggregate undiscounted deficiency payments total approximately $864.0 million. 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.

Subsequent to December 31, 2015, the Company entered into amendments to certain oil gathering and gas gathering agreements related to certain of its Eagle Ford shale assets, neither of which previously had a minimum volume commitment, in order to obtain more favorable rates and terms. Under these amendments, the Company is now committed to deliver 310 Bcf of natural gas and 41 MMBbl of oil through 2034. In the event that the Company delivers no product, the aggregate undiscounted deficiency payments under these amended agreements would be approximately $360.8 million. Subsequent to December 31, 2015, the Company also entered into an amendment to a gas gathering agreement related to certain of its other Eagle Ford shale assets, which reduced the Company’s volume commitment amount as of December 31, 2015, by 829 Bcf and reduced the aggregate undiscounted deficiency payments by $118.2 million.

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, net of sublease income, for the years ended December 31, 2015, 2014, and 2013, was $6.1 million, $6.5 million, and $5.7 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.

The Company is subject to routine severance, royalty and joint interest audits from regulatory authorities, non-operators and others, as the case may be, and records accruals for estimated exposure when a claim is deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise from third party interpretations of the Company’s contracts or otherwise affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices that royalty owners are paid for production from their leases, allowable costs under joint interest arrangements, and other matters. At December 31, 2015, the Company had $5.3 million accrued for estimated exposure related to claims for payment of royalties on certain Federal and Indian leases. Although the Company believes that it has properly estimated its exposure with respect to the various contracts, laws and regulations, administrative rulings, and interpretations thereof, adjustments could be required as new interpretations and regulations arise.

Note 7 – Compensation Plans

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, 2015, 2.8 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, an 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, although the last grant was in 2004, and all remaining stock options were exercised during the year ended December 31, 2014.

Performance Share Units Under the Equity Plan

The Company grants PSUs to eligible employees as a part of its long-term equity compensation program. The number of shares of the Company's common stock issued to settle PSUs ranges from 0% to 200% of the number of PSUs awarded and is determined based on certain performance criteria over a three-year measurement 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. Compensation expense for PSUs is recognized within general and administrative and exploration expense over the vesting periods of the respective awards.

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.

The Company records compensation expense associated with the issuance of PSUs based on the fair value of the awards as of the date of grant. Total compensation expense recorded for PSUs was $10.6 million, $16.0 million, and $16.8 million for the years ended December 31, 2015, 2014, and 2013, respectively. As of December 31, 2015, there was $18.4 million of total unrecognized expense related to PSUs, which is being amortized through 2018.

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

	For the Years Ended December 31,					
	2015		2014		2013	
	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)]	433,660	$ 73.63	572,469	$ 66.07	669,308	$ 63.91
Granted [(1)]	320,753	$ 45.34	202,404	$ 94.66	274,831	$ 64.13
Vested [(1)]	(76,438)	$ 51.76	(206,830)	$ 64.79	(345,005)	$ 60.06
Forfeited [(1)]	(51,647)	$ 73.62	(134,383)	$ 86.72	(26,665)	$ 69.74
Non-vested at end of year[(1)]	626,328	$ 61.81	433,660	$ 73.63	572,469	$ 66.07

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

The fair value of the PSUs granted in 2015, 2014, and 2013 was $14.5 million, $19.2 million, and $17.6 million, respectively. The PSUs granted in 2015, 2014, and 2013 will remain unvested until the third anniversary date of their issuance, at which time they will fully vest, unless the employee is retirement eligible in which case the PSUs vest immediately upon attainment of retirement age.

The total fair value of PSUs that vested during the years ended December 31, 2015, 2014, and 2013 was $4.0 million, $13.4 million, and $20.7 million, respectively.

During the years ended December 31, 2015, 2014, and 2013, the Company issued 188,279, 85,121, and 387,461 net shares, respectively, of common stock for PSUs granted in 2012, 2011, and 2010 that earned a 1.0, 0.55, and 1.725 multiplier, respectively. The Company and the majority of grant recipients mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Plan and individual award agreements. As a result, the Company withheld 100,683, 45,042, and 200,050 shares, respectively, to satisfy income and payroll tax withholding obligations that arose upon the delivery of the shares underlying the PSUs in 2015, 2014, and 2013, respectively.

Restricted Stock Units Under the Equity Plan

The Company grants RSUs to eligible employees as part of its long-term 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 to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period. Compensation expense for RSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the award.

Total compensation expense recorded for RSUs for the years ended December 31, 2015, 2014, and 2013, was $13.4 million, $13.9 million, and $13.1 million, respectively. As of December 31, 2015, there was $19.3 million of total unrecognized expense related to unvested RSU awards, which is being amortized through 2018. 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 of the grant.

A summary of the status and activity of non-vested RSUs is presented below:

	For the Years Ended December 31,					
	2015		2014		2013	
	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	515,724	$68.29	580,431	$57.05	496,244	$51.81
Granted	356,246	$43.72	234,560	$83.98	329,939	$60.01
Vested	(278,289)	$63.12	(253,031)	$58.19	(207,376)	$49.73
Forfeited	(49,944)	$66.53	(46,236)	$62.06	(38,376)	$54.37
Non-vested at end of year	543,737	$55.01	515,724	$68.29	580,431	$57.05

The fair value of RSUs granted in 2015, 2014, and 2013 was $15.6 million, $19.7 million, and $19.8 million, respectively. The RSUs granted in 2015, 2014, and 2013 vest one-third of the total grant on each of the next three anniversaries of the date of the grant.

The total fair value of RSUs that vested during the years ended December 31, 2015, 2014, and 2013, was $17.6 million, $14.7 million, and $10.3 million, respectively.

During the years ended December 31, 2015, 2014, and 2013, the Company settled 278,289, 253,031, and 207,378 RSUs, respectively. The Company and the majority of grant recipients mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Plan and individual award agreements. As a result, the Company issued net shares of common stock of 187,244, 171,597, and 139,391 for 2015, 2014, and 2013, respectively. The remaining 91,045, 81,434, and 67,987 shares were withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying the RSUs for 2015, 2014, and 2013, respectively.

Stock Option Grants Under the Equity 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, 2015, and 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 years ended December 31, 2014, and 2013, is presented in the following table:

	Shares	Weighted - Average Exercise Price	Aggregate Intrinsic Value
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 received from stock options exercised for the years ended December 31, 2014, and 2013, was $4.0 million and $3.2 million, respectively.

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, 2015, 2014, and 2013.

Director Shares

In 2015, 2014, and 2013, the Company issued 37,950, 27,677, and 28,169 shares, respectively, of its common stock to its non-employee directors under the Company's Equity Plan. Additionally, the Company issued 1,953 shares to the Company's former Chief Executive Officer in 2015 for his service as a director through May 2015, following his retirement as an officer of the Company. The Company recorded compensation expense related to these issuances of $1.6 million, $1.6 million, and $1.4 million for the years ended December 31, 2015, 2014, and 2013, 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 to the Company by the director, in which case that director's shares vest upon the earlier of the completion of the one year service period or the director retiring from the Board of Directors.

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 value from purchases for each calendar year. The purchase price of the stock is 85% of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP have no restriction period. The ESPP is intended to qualify under Section 423 of the IRC. The Company had approximately 0.9 million shares available for issuance under the ESPP as of December 31, 2015. There were 197,214, 83,136, and 77,427 shares issued under the ESPP in 2015, 2014, and 2013, respectively. Total proceeds to the Company for the issuance of these shares were $4.8 million, $4.1 million, and $3.7 million for the years ended December 31, 2015, 2014, and 2013, respectively.

The fair value of ESPP grants is 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,					
	2015		2014		2013	
Risk free interest rate	0.1	%	0.1	%	0.1	%
Dividend yield	0.2	%	0.1	%	0.2	%
Volatility factor of the expected market price of the Company’s common stock	61.2	%	33.0	%	41.1	%
Expected life (in years)	0.5		0.5		0.5	

The Company expensed $1.8 million, $1.1 million, and $1.1 million for the years ended December 31, 2015, 2014, and 2013, respectively, based on the estimated fair value of the ESPP grants.

401(k) Plan

The Company has a defined contribution 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 performance bonus, and may make additional contributions at its discretion. The Company matches contributions made by employees hired after December 31, 2014, up to nine percent of the employee’s base salary and performance bonus in lieu of pension plan benefits. Please refer to Note 8 - Pension Benefits for additional discussion of change to pension benefits. The Company’s matching contributions to the 401(k) Plan were $5.6 million, $6.4 million, and $4.2 million for the years ended December 31, 2015, 2014, and 2013, respectively. No discretionary contributions were made by the Company to the 401(k) Plan for any of these years.

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,		
	2015	2014	2013
	(in thousands)		
General and administrative expense	$3,239	$8,326	$13,734
Exploration expense	259	690	1,310
Total	$3,498	$9,016	$15,044

Additionally, the Company made or accrued cash payments under the Net Profits Plan of $3.8 million, $8.3 million, and $10.3 million for the years ended December 31, 2015, 2014, and 2013, respectively, as a result of divestitures of properties subject to the Net Profits Plan. These cash payments are accounted for as a reduction in the net gain 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. As time has passed, the amount distributed relating to prospective exploration efforts has become insignificant as more 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”). The Company froze the Pension Plans to new participants, effective as of December 31, 2015. Employees participating in the Pension Plans as of December 31, 2015, will continue to earn benefits.
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,	
	2015	2014
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$57,867	$43,285
Service cost	7,949	6,335
Interest cost	2,496	2,191
Actuarial loss	2,397	8,821
Benefits paid	(8,162)	(2,765)
Projected benefit obligation at end of year	62,547	57,867
Change in plan assets:		
Fair value of plan assets at beginning of year	27,940	24,658
Actual return on plan assets	(410)	737
Employer contribution	6,401	5,310
Benefits paid	(8,162)	(2,765)
Fair value of plan assets at end of year	25,769	27,940
Funded status at end of year	$(36,778)	$(29,927)

The Company's underfunded status for the Pension Plans as of December 31, 2015, and 2014, is $36.8 million and $29.9 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 year ended December 31, 2015. 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,	
	2015	2014
	(in thousands)	
Projected benefit obligation	$62,547	$57,867
Accumulated benefit obligation	$46,439	$43,205
Less: Fair value of plan assets	(25,769)	(27,940)
Underfunded accumulated benefit obligation	$20,670	$15,265

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, 2015 and 2014, consist of:

	As of December 31,	
	2015	2014
	(in thousands)	
Unrecognized actuarial losses	$20,966	$17,812
Unrecognized prior service costs	101	118
Unrecognized transition obligation	—	—
Accumulated other comprehensive loss	$21,067	$17,930

The estimated net loss that will be amortized from accumulated other comprehensive loss into net periodic benefit cost over the next fiscal year is $1.5 million.

Pre-tax changes recognized in other comprehensive income (loss) during 2015, 2014, and 2013, were as follows:

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Net actuarial gain (loss)	$(4,990)	$(10,062)	$2,766
Prior service cost	—	—	—
Less:			
Amortization of prior service cost	(17)	(17)	(17)
Amortization of net actuarial loss	(1,486)	(689)	(1,222)
Settlements	(350)	—	—
Total other comprehensive income (loss)	$(3,137)	$(9,356)	$4,005

Components of Net Periodic Benefit Cost for the Pension Plans

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Components of net periodic benefit cost:			
Service cost	$7,949	$6,335	$6,291
Interest cost	2,496	2,191	1,627
Expected return on plan assets that reduces periodic pension cost	(2,182)	(1,978)	(1,538)
Amortization of prior service cost	17	17	17
Amortization of net actuarial loss	1,486	689	1,222
Settlements	350	—	—
Net periodic benefit cost	$10,116	$7,254	$7,619

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,		
	2015	2014	2013
Projected benefit obligation			
Discount rate	4.7%	4.3%	5.0%
Rate of compensation increase	6.2%	6.2%	6.2%
Net periodic benefit cost			
Discount rate	4.3%	5.0%	3.9%
Expected return on plan assets [(1)]	7.5%	7.5%	7.5%
Rate of compensation increase	6.2%	6.2%	6.2%

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(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	2016		2015		2014	
Equity securities	42.0	%	39.1	%	39.6	%
Fixed income securities	35.0	%	34.0	%	33.9	%
Other securities	23.0	%	26.9	%	26.5	%
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 2015 and 2014. 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, 2015 and 2014, utilizing the fair value hierarchy discussed in Note 11 – Fair Value Measurements are as follows:

	Actual Asset Allocation		Total	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(in thousands)			
As of December 31, 2015						
Cash	—	%	$—	$—	$—	$—
Equity Securities:						
Domestic (1)	26.1	%	6,729	4,943	1,786	—
International (2)	13.0	%	3,353	3,353	—	—
Total Equity Securities	39.1	%	10,082	8,296	1,786	—
Fixed Income Securities:						
High-Yield Bonds (3)	2.8	%	722	722	—	—
Core Fixed Income (4)	22.5	%	5,789	5,789	—	—
Floating Rate Corp Loans (5)	8.7	%	2,247	2,247	—	—
Total Fixed Income Securities	34.0	%	8,758	8,758	—	—
Other Securities:						
Commodities (6)	2.7	%	700	700	—	—
Real Estate (7)	5.8	%	1,499	—	—	1,499
Collective Investment Trusts (8)	4.6	%	1,184	—	1,184	—
Hedge Fund (9)	13.8	%	3,546	—	—	3,546
Total Other Securities	26.9	%	6,929	700	1,184	5,045
Total Investments	100.0	%	$25,769	$17,754	$2,970	$5,045
As of 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:						
High-Yield Bonds (3)	2.9	%	797	797	—	—
Core Fixed Income (4)	22.4	%	6,247	6,247	—	—
Floating Rate Corp Loans (5)	8.6	%	2,413	2,413	—	—
Total Fixed Income Securities	33.9	%	9,457	9,457	—	—
Other Securities:						
Commodities (6)	2.9	%	810	810	—	—
Real Estate (7)	4.7	%	1,327	—	—	1,327
Collective Investment Trusts (8)	4.1	%	1,149	—	1,149	—
Hedge Fund (9)	14.8	%	4,130	593	—	3,537
Total Other Securities	26.5	%	7,416	1,403	1,149	4,864
Total Investments	100.0	%	$27,940	$19,908	$3,168	$4,864

(1) Level 1 equity securities consist of United States large and small capitalization companies, which are actively traded securities that can be sold upon demand. Level 2 equity securities are investments in a collective investment fund that is valued at net asset value based on the value of the underlying investments and total units outstanding on a daily basis. The objective of this fund is to approximate the S&P 500 by investing in one or more collective investment funds.

(2) International equity securities consists of a well-diversified portfolio of holdings of mostly large issuers organized in developed countries with liquid markets, commingled with investments in equity securities of issuers located in emerging markets and believed to have strong sustainable financial productivity at attractive valuations.

(3) High-yield bonds consist of non-investment grade fixed income securities. The investment objective is to obtain high current income. Due to the increased level of default risk, security selection focuses on credit-risk analysis.

(4) The objective is to achieve value added from sector or issue selection by constructing a portfolio to approximate the investment results of the Barclay's Capital Aggregate Bond Index with a modest amount of variability in duration around the index.

(5) Investments consist of floating rate bank loans. The interest rates on these loans are typically reset on a periodic basis to account for changes in the level of interest rates.

(6) Investments with exposure to commodity price movements, primarily through the use of futures, swaps and other commodity-linked securities.

(7) The investment objective of direct real estate is to provide current income with the potential for long-term capital appreciation. Ownership in real estate entails a long-term time horizon, periodic valuations, and potentially low liquidity.

(8) Collective investment trusts invest in short-term investments and are valued at the net asset value of the collective investment trust. The net asset value, as provided by the trustee, is used as a practical expedient to estimate fair value. The net asset value is based on the fair value of the underlying investments held by the fund less its liabilities.

(9) The hedge fund portfolio includes an investment in an actively traded global mutual fund that focuses on alternative investments and a hedge fund of funds that invests both long and short using a variety of investment strategies.

Included below is a summary of the changes in Level 3 plan assets (in thousands):

Balance at January 1, 2014	$3,421
Purchases	1,232
Realized gain on assets	144
Unrealized gain on assets	67
Balance at December 31, 2014	$4,864
Purchases	—
Realized gain on assets	165
Unrealized gain on assets	16
Balance at December 31, 2015	$5,045

Contributions

The Company contributed $6.4 million, $5.3 million, and $5.0 million, to the Pension Plans in the years ended December 31, 2015, 2014, and 2013, respectively. The Company expects to make a $5.8 million contribution to the Pension Plans in 2016.

Benefit Payments

The Pension Plans made actual benefit payments of $8.2 million, $2.8 million, and $3.3 million in the years ended December 31, 2015, 2014, and 2013, respectively. Expected benefit payments over the next 10 years are as follows:

Years Ending December 31,	(in thousands)
2016	$3,618
2017	$4,350
2018	$4,605
2019	$6,057
2020	$6,846
2021 through 2025	$47,188

Note 9 – Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the plugging and abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation ("ARO") and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled 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. Cash paid to settle asset retirement obligations is included in the operating section of the Company's accompanying statements of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience in plugging and abandoning wells, estimated economic lives, estimated plugging and abandonment cost, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's plugging and abandonment liabilities range from 5.5 percent to 12 percent. In periods subsequent to initial measurement of the liability, the Company must recognize period-to-period changes in the liability resulting from the passage of time, revisions to either the amount of the original estimate of undiscounted cash flows or changes in inflation factors or the Company's credit-adjusted risk-free rate as market conditions warrant.

A reconciliation of the Company's total asset retirement obligation liability is as follows:

	As of December 31,			
	2015		2014	
	(in thousands)			
Beginning asset retirement obligation	$122,124		$121,186	
Liabilities incurred	14,471		13,506	
Liabilities settled	(24,781	)	(11,372	)
Accretion expense	5,091		6,090	
Revision to estimated cash flows	23,969		(7,286	)
Ending asset retirement obligation	$140,874		$122,124	

As of December 31, 2015 and 2014, accounts payable and accrued expenses contain $3.3 million and $1.3 million, respectively, related to the Company's current asset retirement obligation liability for estimated plugging and abandonment costs associated with platform structures that are being retired, which are also included in the table above.

Note 10 – Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. The Company’s derivative contracts consist of swap arrangements for oil, gas, and NGLs.

As of December 31, 2015, the Company had commodity derivative contracts outstanding through the second quarter of 2020 for a total of 5.6 million Bbls of oil production, 172.7 million MMBtu of gas production, and 13.0 million Bbls of NGL production.

In a typical commodity swap agreement, if the agreed upon published third-party index price (“index price”) is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of December 31, 2015:

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
First quarter 2016	1,868,000	$86.93
Second quarter 2016	1,752,000	$86.73
Third quarter 2016	1,170,000	$90.29
Fourth quarter 2016	780,000	$90.05
All oil swaps	5,570,000	

Natural Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)
First quarter 2016	23,341,000	$3.82
Second quarter 2016	20,780,000	$3.40
Third quarter 2016	18,829,000	$3.38
Fourth quarter 2016	17,236,000	$3.82
2017	37,528,000	$4.09
2018	30,606,000	$4.27
2019	24,415,000	$4.34
All gas swaps*	172,735,000	

*Natural gas swaps are comprised of IF El Paso Permian (2%), IF HSC (95%), IF NGPL TXOK (1%), and IF NNG Ventura (2%).

NGL Swaps

	OPIS Purity Ethane Mont Belvieu		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPIS Isobutane Mont Belvieu Non-TET	
Contract Period	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)
First quarter 2016	926,000	$ 8.29	1,059,000	$ 19.60	143,000	$ 25.62	122,000	$ 25.87
Second quarter 2016	828,000	$ 8.28	949,000	$ 19.64	130,000	$ 25.62	111,000	$ 25.87
Third quarter 2016	751,000	$ 8.70	862,000	$ 19.03	—	$ —	—	$ —
Fourth quarter 2016	688,000	$ 8.71	791,000	$ 18.53	—	$ —	—	$ —
2017	2,271,000	$ 9.16	—	$ —	—	$ —	—	$ —
2018	1,671,000	$ 10.65	—	$ —	—	$ —	—	$ —
2019	1,200,000	$ 10.92	—	$ —	—	$ —	—	$ —
2020	539,000	$ 11.13	—	$ —	—	$ —	—	$ —
Total NGL swaps	8,874,000		3,661,000		273,000		233,000	

Commodity Derivative Contracts Entered Into After December 31, 2015

Subsequent to December 31, 2015, the Company restructured certain of its gas derivative contracts by buying fixed price volumes to exactly offset existing 2018 and 2019 fixed price swap contracts totaling 55.0 million MMBtu. The Company then entered into new 2017 fixed price swap contracts totaling 38.6 million MMBtu with a contract price of $4.43 per MMBtu. No cash or other consideration was included as part of the restructuring. The net result of buying fixed price volumes in 2018 and 2019 is that the Company no longer has protection against natural gas price volatility in those years. These updated contracts are reflected in the following table, which summarizes the approximate gas volumes and average contract prices of contracts the Company had in place as of February 17, 2016, including derivatives contracts for settlement anytime during the first quarter of 2016 and later periods:

Natural Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Purchased Volumes	Weighted-Average Contract Price	Total Volumes
	(MMBtu)	(per MMBtu)	(MMBtu)	(per MMBtu)	(MMBtu)
First quarter 2016	23,341,000	$3.82	—	$—	23,341,000
Second quarter 2016	20,780,000	$3.40	—	$—	20,780,000
Third quarter 2016	18,829,000	$3.38	—	$—	18,829,000
Fourth quarter 2016	17,236,000	$3.82	—	$—	17,236,000
2017	76,135,000	$4.26	—	$—	76,135,000
2018	30,606,000	$4.27	(30,606,000)	$4.27	—
2019	24,415,000	$4.34	(24,415,000)	$4.34	—
All gas swaps*	211,342,000		(55,021,000)		156,321,000

*Total volumes of natural gas swaps are comprised of IF El Paso Permian (2%), IF HSC (96%), IF NGPL TXOK (1%), and IF NNG Ventura (1%).

Additionally, subsequent to December 31, 2015, the Company entered into NGL fixed price swap contracts for 1.6 million Bbls of ethane production through 2018 with an average contract price of $8.67 per Bbl and 235,000 Bbls of isobutane production through the fourth quarter of 2016 with a contract price of $22.58 per Bbl.

Derivative Assets and Liabilities Fair Value

The Company’s commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net asset of $488.4 million and $592.1 million at December 31, 2015 and 2014, respectively.

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of December 31, 2015			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current assets	$367,710	Current liabilities	$8
Commodity Contracts	Noncurrent assets	120,701	Noncurrent liabilities	—
Derivatives not designated as hedging instruments		$488,411		$8

	As of December 31, 2014			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current assets	$402,668	Current liabilities	$—
Commodity Contracts	Noncurrent assets	189,540	Noncurrent liabilities	70
Derivatives not designated as hedging instruments		$592,208		$70

Offsetting of Derivative Assets and Liabilities

As of December 31, 2015 and 2014, all derivative instruments held by the Company were subject to master netting arrangements by various financial institutions. In general, the terms of the Company’s agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that settle on the same date and in the same currency. The Company’s agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company’s accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company’s derivative contracts:

	Derivative Assets		Derivative Liabilities	
	As of December 31,		As of December 31,	
Offsetting of Derivative Assets and Liabilities	2015	2014	2015	2014
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$488,411	$592,208	$(8)	$(70)
Amounts not offset in the accompanying balance sheets	(8)	(70)	8	70
Net amounts	$488,403	$592,138	$—	$—

Discontinuance of Cash Flow Hedge Accounting

As of January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010. Fair values at December 31, 2010, were frozen in AOCL as of the de-designation date and were reclassified into earnings as the original derivative transactions settled. As of September 30, 2013, all commodity derivative contracts that had been previously designated as cash flow hedges had settled and had been reclassified into earnings from AOCL.

Subsequent to December 31, 2010, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL. The Company had no derivatives designated as cash flow hedges for the years ended December 31, 2015, 2014, and 2013, and no new gains or losses were deferred to AOCL during these respective years. Please refer to Note 11 - Fair Value Measurements for more information regarding the Company’s derivative instruments, including its valuation techniques.

The following table summarizes the components of derivative gain presented in the accompanying statements of operations:

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Derivative settlement (gain) loss:			
Oil contracts	$(362,219)	$(28,410)	$15,161
Gas contracts [1]	(123,180)	26,706	(30,338)
NGL contracts	(27,167)	(10,911)	(6,885)
Total derivative settlement gain	$(512,566)	$(12,615)	$(22,062)
Total derivative (gain) loss:			
Oil contracts	$(191,165)	$(457,082)	$14,665
Gas contracts	(189,734)	(93,267)	(14,053)
NGL contracts	(27,932)	(32,915)	(3,692)
Total derivative gain	$(408,831)	$(583,264)	$(3,080)

(1) Natural gas derivative settlements for the years ended December 31, 2015, and 2014, include $15.3 million and $5.6 million, respectively, of early settlements of futures contracts as a result of divesting assets in the Company's Mid-Continent region.

The following table details the effect of derivative instruments on AOCL and the accompanying statements of operations (net of income tax):

	Derivatives	Location on Accompanying Statements of Operations	For the Years Ended December 31, 2015	2014	2013
			(in thousands)		
Amount reclassified from AOCL	Commodity Contracts	Other operating revenues	$—	$—	$1,115

The realized net hedge loss for the year ended December 31, 2013, shown net of income tax in the table above, is comprised of realized settlements on commodity derivative contracts that were previously designated as cash flow hedges. Realized hedge gains or losses from the settlement of commodity derivatives previously designated as cash flow hedges are reported in the other operating revenues line item on the accompanying statements of operations. The Company realized a pre-tax net loss of $1.8 million from its commodity derivative contracts that were previously designated as cash flow hedges for the year ended December 31, 2013.

Credit Related Contingent Features

As of December 31, 2015, and through the filing date of this report, all of the Company's derivative counterparties were members of the Company's credit facility lender group. The Company's obligations under its credit facility and derivative contracts are secured by mortgages on assets having a value equal to at least 75 percent of the total value of the Company's proved oil and gas properties.

Note 11 – Fair Value Measurements

The Company follows fair value measurement accounting guidance for all assets and liabilities measured at fair value. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – significant inputs to the valuation model are unobservable

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they are classified within the fair value hierarchy as of December 31, 2015:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$488,411	$—
Proved oil and gas properties (2)	$—	$—	$124,184
Other property and equipment (2)	$—	$—	$629
Liabilities:			
Derivatives (1)	$—	$8	$—
Net Profits Plan (1)	$—	$—	$7,611

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset that is measured at fair value on a nonrecurring basis.

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they are classified within the fair value hierarchy as of December 31, 2014:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$592,208	$—
Proved oil and gas properties (2)	$—	$—	$33,423
Oil and gas properties held for sale (2)	$—	$—	$17,891
Liabilities:			
Derivatives (1)	$—	$70	$—
Net Profits Plan (1)	$—	$—	$27,136

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset that is measured at fair value on a nonrecurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may require counterparties to post collateral if their ratings deteriorate. In some instances, the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any derivative liability position. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current credit facility margins, and any change in such margins since the last measurement date. All of the Company's derivative counterparties are members of the Company's credit facility lender group.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with authoritative accounting guidance and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Refer to Note 10 - Derivative Financial Instruments for more information regarding the Company's derivative instruments.

Net Profits Plan
The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable and are therefore classified as Level 3 inputs. The Company employs the income valuation technique, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil, gas, and NGL commodity prices driving net cash flows and the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and lower commodity prices result in a smaller Net Profits Plan liability.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. Discount rates of 10 percent and 12 percent were used to calculate this liability as of December 31, 2015, and 2014, respectively, and are intended to represent the Company’s best estimate of the present value of expected future payments under the Net Profits Plan.

The Company’s estimate of its liability is highly dependent on commodity prices, cost assumptions, discount rates, and overall market conditions. The Company regularly assesses the current market environment. The Net Profits Plan liability is determined using price assumptions of five one-year strip prices with the fifth year’s pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of the forecasted production covered by derivative contracts in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the oil, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at December 31, 2015, would differ by approximately $1.1 million. A one percent increase or decrease in the discount rate would result in a change of approximately $300,000. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company’s estimate of fair value of its Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company’s calculation of fair value of the Net Profits Plan’s future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company’s own calculations and estimates.

The following table reflects the activity for the Company's Net Profits Plan liability measured at fair value using Level 3 inputs:

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Beginning balance	$27,136	$56,985	$78,827
Net increase (decrease) in liability [(1)]	(12,238)	(12,492)	3,527
Net settlements [(1)] [(2)]	(7,287)	(17,357)	(25,369)
Transfers in (out) of Level 3	—	—	—
Ending balance	$7,611	$27,136	$56,985

(1) Net changes in the Company's Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(2) Settlements represent cash payments made or accrued under the Net Profits Plan. The amounts in the table include cash payments made or accrued under the Net Profits Plan of $3.8 million, $8.3 million, and $10.3 million for the years ended December 31, 2015, 2014, and 2013, respectively, as a result of the divestitures of properties subject to the Net Profits Plan.

Long-Term Debt

The following table reflects the fair value of the Senior Notes measured using Level 1 inputs based on quoted secondary market trading prices. The Senior Notes were not presented at fair value on the accompanying balance sheets as of December 31, 2015 or 2014, as they are recorded at carrying value, net of unamortized deferred financing costs.

	As of December 31,	
	2015	2014
	(in thousands)	
2019 Notes [(1)]	$—	$350,018
2021 Notes	$262,938	$343,000
2022 Notes	$440,250	$556,500
2023 Notes	$296,000	$379,000
2024 Notes	$334,065	$435,000
2025 Notes [(1)]	$326,875	$—

(1) The 2019 Notes were fully redeemed on June 22, 2015 and the 2025 Notes were issued on May 21, 2015.

The carrying value of the Company's credit facility approximates its fair value, as the applicable interest rates are floating, based on prevailing market rates.

Proved and Unproved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts representative of the current operating environment, as selected by the Company's management. The calculation of the discount rate is based on the best information available and was estimated to be 10 percent to 15 percent based on the reservoir specific weightings of future estimated proved and unproved cash flows as of December 31, 2015. A 12 percent discount rate was

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estimated as of December 31, 2014. The Company believes the discount rate is representative of current market conditions and takes into account estimates of future cash payments, reserve categories, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The prices for oil and gas are forecast 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 forecast using OPIS Mont Belvieu pricing, 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. The Company recorded impairment of proved oil and gas properties expense of $468.7 million for the year ended December 31, 2015, due to the decline in proved and risk-adjusted probable and possible reserve expected cash flows, driven by the continued commodity price declines. Impairments were recorded mainly in the Company’s east Texas and Powder River Basin programs with smaller impacts on other legacy and non-core assets in the Rocky Mountain region. These assets were impaired to fair value totaling $124.2 million as of December 31, 2015. The Company recorded impairment of proved oil and gas properties expense of $84.5 million for the year ended December 31, 2014, resulting from the significant decline in commodity prices at the end of 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. As of December 31, 2014, proved oil and gas properties measured at fair value totaled $33.4 million.

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values. The Company recorded abandonment and impairment of unproved oil and gas properties expense of $78.6 million and $75.6 million for the years ended December 31, 2015, and 2014, respectively, resulting from lease expirations and acreage the Company no longer intended to develop in light of changes in drilling plans in response to the decline in commodity prices. Unproved properties measured at fair value were zero in the accompanying balance sheets as of December 31, 2015, and 2014.

Other property and equipment costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. Fair value of other property and equipment is valued using an income valuation technique or market approach depending on the quality of information available to support management’s assumptions and the circumstances. The valuation includes consideration of the proved and unproved assets supported by the property and equipment, future cash flows associated with the assets, and fixed costs necessary to operate and maintain the assets. The Company recorded impairment of other property and equipment expense of $49.4 million for the year ended December 31, 2015, on the Company’s gathering system assets in its east Texas program. These assets were impaired in conjunction with the impairment of the associated proved and unproved properties, which the Company does not intend to develop during an environment of sustained low commodity prices. The fair value of these assets at December 31, 2015, was $629,000.

Proved properties classified as held for sale, including the corresponding asset retirement obligation liability, are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties, if available. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company estimates acreage value based on the price received for similar acreage in recent transactions by the Company or other market participants in the principal market. For the years ended December 31, 2015, and 2014, write-downs on certain assets held for sale totaled $98.6 million and $27.6 million, respectively. These write-downs are included within the net gain on divestiture activity line item on the accompanying statements of operations. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions for further discussion. There were no assets held for sale recorded at fair value as of December 31, 2015, as the carrying value was below the estimated fair value less costs to sell. As of December 31, 2014, assets held for sale measured at fair value totaled $17.9 million.

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation. Refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions for additional information on the fair value of assets acquired during 2014.

Note 12 - Acquisition and Development Agreement

In June 2011, the Company entered into an Acquisition and Development Agreement with Mitsui (the "Acquisition and Development Agreement"). Pursuant to the Acquisition and Development Agreement, the Company agreed to transfer to Mitsui a 12.5 percent working interest in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick, and Webb Counties, Texas. As consideration for the oil and gas interests transferred, Mitsui agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to the Company's remaining interest in these assets until Mitsui expended an aggregate $680.0 million on behalf of the Company. The Acquisition and Development Agreement also provided for reimbursement of capital expenditures and other costs, net of revenues, paid by the Company that were attributable to the transferred interest during the period between the effective date and the closing date, which the parties agreed would be applied over the carry period to cover the Company's remaining 10 percent of drilling and completion costs for the affected acreage.

During the second quarter of 2014, the remainder of the carry under the Acquisition and Development Agreement was expended. Accordingly, the Company accrued and funded its full share of drilling and completion costs in its non-operated Eagle Ford shale program for the remainder of 2014 and all of 2015.

Note 13 - Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2015, 2014, and 2013. The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same year:

	For the Years Ended December 31,					
	2015		2014		2013	
	(in thousands)					
Beginning balance on January 1,	$43,589		$34,527		$9,100	
Additions to capitalized exploratory well costs pending the determination of proved reserves	11,952		43,589		34,527	
Divestitures	(809	)	—		—	
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(18,485	)	(33,340	)	(9,100	)
Capitalized exploratory well costs charged to expense	(24,295	)	(1,187	)	—	
Ending balance at December 31,	$11,952		$43,589		$34,527	

As of December 31, 2015, there were no exploratory well costs that were capitalized for more than one year.

Supplemental Oil and Gas Information (unaudited)

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 Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Development costs (1)	$1,234,114	$1,782,324	$1,350,116
Exploration costs	132,465	288,270	168,612
Acquisitions			
Proved properties	10,040	272,902	29,859
Unproved properties (2)	18,382	368,208	172,546
Total, including asset retirement obligation (3)(4)	$1,395,001	$2,711,704	$1,721,133

(1) Includes facility costs of $75.6 million, $75.1 million, and $49.5 million for the years ended December 31, 2015, 2014, and 2013, respectively.

(2) Includes $924,000, $288.7 million, and $58.5 million of unproved properties acquired as part of proved property acquisitions for the years ended December 31, 2015, 2014, and 2013, respectively. The remaining balance relates to leasing activity.

(3) Includes capitalized interest of $25.1 million, $16.2 million, and $11.0 million for the years ended December 31, 2015, 2014, and 2013, respectively.

(4) Includes amounts relating to estimated asset retirement obligations of $38.5 million, $11.4 million, and $26.8 million for the years ended December 31, 2015, 2014, and 2013, respectively.

Oil and Gas Reserve Quantities

The reserve estimates presented below were made in accordance with GAAP requirements for disclosures about oil and gas producing activities and SEC rules for oil and gas reporting of reserve estimation and disclosure.

Proved reserves are the estimated 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. All of the Company’s estimated proved reserves are located in the United States.

The table below presents a summary of changes in the Company's estimated proved reserves for each of the years in the three-year period ended December 31, 2015. The Company engaged Ryder Scott to audit internal engineering estimates for at least 80 percent of the Company's total calculated proved reserve PV-10 for each year presented. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

	For the Years Ended December 31,								
	2015 (1)			2014 (2)			2013 (3)		
	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)
Total proved reserves:									
Beginning of year	169.7	1,466.5	133.5	126.6	1,189.3	103.9	92.2	833.4	62.3
Revisions of previous estimate	(46.2)	(369.6)	(40.6)	(5.1)	46.0	7.8	(5.2)	68.8	(1.3)
Discoveries and extensions	16.9	122.3	9.3	15.0	103.5	10.5	34.6	399.2	39.8
Infill reserves in an existing proved field	24.9	356.2	29.7	32.0	270.8	24.1	21.6	118.7	13.2
Sales of reserves (4)	(1.9)	(138.4)	(0.4)	(1.9)	(1.1)	—	(3.4)	(85.1)	(0.6)
Purchases of minerals in place	1.1	0.6	—	19.8	10.9	0.2	0.7	3.6	—
Production	(19.2)	(173.6)	(16.1)	(16.7)	(152.9)	(13.0)	(13.9)	(149.3)	(9.5)
End of year	145.3	1,264.0	115.4	169.7	1,466.5	133.5	126.6	1,189.3	103.9
Proved developed reserves:									
Beginning of year	89.3	784.6	66.7	70.2	569.2	43.8	58.8	483.2	27.2
End of year	75.6	644.4	61.5	89.3	784.6	66.7	70.2	569.2	43.8
Proved undeveloped reserves:									
Beginning of year	80.4	682.0	66.8	56.3	620.1	60.2	33.5	350.2	35.1
End of year	69.6	619.7	53.9	80.4	682.0	66.8	56.3	620.1	60.2

Note: Amounts may not calculate due to rounding.

(1) For the year ended December 31, 2015, the Company added 160.6 MMBOE from its drilling program, the majority of which related to activity in the Eagle Ford shale and Bakken/Three Forks plays. The Company had net negative engineering revisions of 148.6 MMBOE, consisting of 47.3 MMBOE of positive performance revisions in the Eagle Ford shale and Bakken/Three Forks plays resulting from enhanced completions and reductions in operating expenses, offset by a 116.5 MMBOE negative price revision due to the decline in commodity prices in 2015 and the removal of 79.4 MMBOE of proved undeveloped reserves due to the five-year rule.

(2) For the year ended December 31, 2014, the Company added 143.9 MMBOE from its drilling program and had upward engineering revisions of 10.4 MMBOE related primarily to improved performance and lower operating expenses in its operated Eagle Ford assets.

(3) For the year ended December 31, 2013, the Company added 195.5 MMBOE from its drilling program and had upward engineering revisions of 5.0 MMBOE related primarily to an upward performance revision of 4.4 MMBOE.

(4) Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions for additional information on assets divested.

Standardized Measure of Discounted Future Net Cash Flows

The Company computes a standardized measure of future net cash flows and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. Future cash inflows and production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated future reserve quantities. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using the current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10 percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved reserves in place at the end of the period using year-end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value amount. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. The following prices as adjusted for transportation, quality, and basis differentials were used in the calculation of the standardized measure:

	For the Years Ended December 31,		
	2015	2014	2013
Oil (per Bbl)	$42.98	$84.65	$90.19
Gas (per Mcf)	$2.48	$4.63	$3.99
NGLs (per Bbl)	$16.99	$35.48	$35.92

The following summary sets forth the Company’s future net cash flows relating to proved oil, gas, and NGL reserves based on the standardized measure.

	As of December 31,		
	2015	2014	2013
	(in thousands)		
Future cash inflows	$11,337,865	$25,897,730	$19,895,360
Future production costs	(6,234,687)	(9,986,239)	(7,771,747)
Future development costs	(2,005,599)	(3,294,164)	(2,891,325)
Future income taxes	—	(3,511,352)	(2,722,230)
Future net cash flows	3,097,579	9,105,975	6,510,058
10 percent annual discount	(1,228,671)	(3,407,192)	(2,500,619)
Standardized measure of discounted future net cash flows	$1,868,908	$5,698,783	$4,009,439

The principle sources of changes in the standardized measure of discounted future net cash flows are:

	For the Years Ended December 31,		
	2015	2014	2013
	(in thousands)		
Standardized measure, beginning of year	$5,698,783	$4,009,439	$3,021,014
Sales of oil, gas, and NGLs produced, net of production costs	(776,272)	(1,765,666)	(1,602,505)
Net changes in prices and production costs	(4,709,908)	(75,966)	142,199
Extensions, discoveries and other including infill reserves in an existing proved field, net of related costs	386,069	1,819,657	2,309,075
Sales of reserves in place	(262,210)	(49,736)	(259,031)
Purchase of reserves in place	4,686	413,175	30,771
Previously estimated development costs incurred during the period	449,738	1,015,694	581,107
Changes in estimated future development costs	191,447	138,247	68,613
Revisions of previous quantity estimates	(1,819,639)	167,500	82,226
Accretion of discount	761,746	552,852	384,914
Net change in income taxes	1,863,868	(399,587)	(690,953)
Changes in timing and other	80,600	(126,826)	(57,991)
Standardized measure, end of year	$1,868,908	$5,698,783	$4,009,439

Quarterly Financial Information (unaudited)

The Company’s quarterly financial information for fiscal years 2015 and 2014 is as follows (in thousands, except per share amounts):

	First Quarter	Second [2] Quarter	Third [3] Quarter	Fourth [3] [4] Quarter
Year Ended December 31, 2015				
Total operating revenues and other income	$365,934	$516,146	$371,151	$303,734
Total operating expenses	420,369	567,025	339,047	809,307
Income (loss) from operations	$(54,435)	$(50,879)	$32,104	$(505,573)
Loss before income taxes	$(86,511)	$(98,211)	$(1,026)	$(537,113)
Net income (loss)	$(53,058)	$(57,508)	$3,114	$(340,258)
Basic net income (loss) per common share[1]	$(0.79)	$(0.85)	$0.05	$(5.01)
Diluted net income (loss) per common share[1]	$(0.79)	$(0.85)	$0.05	$(5.01)
Dividends declared per common share	$0.05	$—	$0.05	$—
Year Ended December 31, 2014				
Total operating revenues and other income	$632,720	$674,980	$618,786	$595,821
Total operating expenses	504,086	553,264	261,807	37,336
Income from operations	$128,634	$121,716	$356,979	$558,485
Income before income taxes	$104,470	$95,829	$333,686	$530,714
Net income	$65,607	$59,780	$208,938	$331,726
Basic net income per common share[1]	$0.98	$0.89	$3.10	$4.92
Diluted net income per common share[1]	$0.96	$0.88	$3.05	$4.91
Dividends declared per common share	$0.05	$—	$0.05	$—

(1) Amounts may not sum due to rounding.

(2) During the second quarter of 2015, the Company recorded a $71.9 million net gain on divestiture activity resulting from the sale of its Mid-Continent assets offset by write-downs on certain other assets held for sale. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions in Part II, Item 8 of this report for additional information. Additionally, the Company recorded a $16.6 million net loss on the early extinguishment of its 2019 Notes. Please refer to Note 5 - Long-Term Debt in Part II, Item 8 of this report for additional information.

(3) The volatility of commodity prices at the end of 2014 and throughout 2015 has resulted in significant net derivative gains recorded for the years ended December 31, 2015, and 2014, with the third quarter of 2015 including a $212.3 million net derivative gain and the third and fourth quarters of 2014 including a $190.7 million and $616.7 million net derivative gain, respectively. Please refer to the caption Derivative gain included in Comparison of Financial Results and Trends between 2015 and 2014 and between 2014 and 2013 included in Part II, Item 7 of this report for additional discussion.

(4) During the fourth quarter of 2015, the Company recorded $344.2 million of impairment of proved properties expense, $54.6 million of abandonment and impairment of unproved properties expense, and $49.4 million of impairment of other property and equipment expense. During the fourth quarter of 2014, the Company recorded $84.5 million of impairment of proved properties expense and $57.2 million of abandonment and impairment of unproved properties expense. Please refer to the caption Impairment of Proved and Unproved Properties included in Note 1 - Summary of Significant Accounting Policies for additional discussion.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the fourth quarter of 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management’s Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company’s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company’s internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company’s assets that have a material effect on the financial statements.

Because of the inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. Even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of the changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (2013 framework).

Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2015.

The Company’s independent registered public accounting firm has issued an attestation report on the Company’s internal control over financial reporting. That report immediately follows this report.

Report of Independent Registered Public Accounting Firm

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

We have audited SM Energy Company and subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). SM Energy Company and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, SM Energy Company and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of SM Energy Company and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015 of SM Energy Company and subsidiaries and our report dated February 24, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
February 24, 2016

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item concerning SM Energy's Directors, Executive Officers, and corporate governance is incorporated by reference to the information provided under the captions "Proposal 1 - Election of Directors," "Information about Executive Officers," and "Corporate Governance" in SM Energy's definitive proxy statement for the 2016 annual meeting of stockholders to be filed within 120 days from December 31, 2015.

The information required by this Item concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the information provided under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in SM Energy's definitive proxy statement for the 2016 annual meeting of stockholders to be filed within 120 days from December 31, 2015.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions "Executive Compensation" and "Director Compensation" in SM Energy's definitive proxy statement for the 2016 annual meeting of stockholders to be filed within 120 days from December 31, 2015.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption "Security Ownership of Certain Beneficial Owners and Management" in SM Energy's definitive proxy statement for the 2016 annual meeting of stockholders to be filed within 120 days from December 31, 2015.

Securities Authorized for Issuance Under Equity Compensation Plans. SM Energy has the Equity Plan under which options and shares of SM Energy common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. Our stockholders have approved this plan. See Note 7 – Compensation Plans included in Part II, Item 8 of this report for further information about the material terms of our equity compensation plans. The following table is a summary of the shares of common stock authorized for issuance under the equity compensation plans as of December 31, 2015:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Equity Incentive Compensation Plan			
Stock options and incentive stock options (1)	—	$—	
Restricted stock (1)(3)	543,737	N/A	
Performance share units (1)(3)(4)	725,408	N/A	
Total for Equity Incentive Compensation Plan	1,269,145	$—	2,781,642
Employee Stock Purchase Plan (2)	—	—	949,707
Equity compensation plans not approved by security holders	—	—	—
Total for all plans	1,269,145	$—	3,731,349

(1) In May 2006, the stockholders approved the Equity Plan to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, performance shares, performance units, and stock-based awards to key employees, consultants, and members of the Board of Directors of SM Energy or any affiliate of SM Energy. Our Board of Directors approved amendments to the Equity Plan in 2009, 2010, and 2013 and each amended plan was approved by stockholders at the respective annual stockholders' meetings. The awards granted in 2015, 2014, and 2013 under the Equity Plan were 714,949, 464,641, and 632,939, respectively.

(2) Under the SM Energy Company ESPP, eligible employees may purchase shares of our common stock through payroll deductions of up to 15 percent of their eligible compensation. 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 six-month offering period, and 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 Internal Revenue Code. Shares issued under the ESPP totaled 197,214, 83,136, and 77,427 in 2015, 2014, and 2013, respectively.

(3) RSUs and PSUs do not have exercise prices associated with them, but rather a weighted-average per share fair value, which is presented in order to provide additional information regarding the potential dilutive effect of the awards. The weighted-average grant date per share fair value for the outstanding RSUs and PSUs was $55.01 and $63.43, respectively. Please refer to Note 7 - Compensation Plans in Part II, Item 8 of this report for additional discussion.

(4) The number of awards vested assumes a one multiplier. The final number of shares issued upon settlement may vary depending on the three-year multiplier determined at the end of the performance period under the Equity Plan, which ranges from zero to two.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information provided under the captions "Certain Relationships and Related Transactions" and "Corporate Governance" in SM Energy's definitive proxy statement for the 2016 annual meeting of stockholders to be filed within 120 days from December 31, 2015.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the captions "Independent Registered Public Accounting Firm" and "Audit Committee Preapproval Policy and Procedures" in SM Energy's definitive proxy statement for the 2016 annual meeting of stockholders to be filed within 120 days from December 31, 2015.

PART IV
ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
1.1	Underwriting Agreement dated May 7, 2015, among SM Energy Company, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner, & Smith Incorporated and J.P. Morgan Securities LLC, as representatives of the several underwriters (filed as Exhibit 1.1 to the registrant's Current Report on Form 8-K filed on May 8, 2015, and incorporated herein by reference)
2.1	Acquisition and Development Agreement dated June 29, 2011 between SM Energy Company and Mitsui E&P Texas LP (filed as Exhibit 2.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 and incorporated herein by reference)
2.2	First Amendment to Acquisition and Development Agreement dated October 13, 2011 between SM Energy Company and Mitsui E&P Texas LP (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 and incorporated herein by reference)
2.3***	Purchase and Sale Agreement dated November 4, 2013, among SM Energy Company, EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., and EnerVest Energy Institutional Fund XIII-WIC, L.P. (filed as Exhibit 2.4 to the registrant's Amendment to the Annual Report on Form 10-K/A filed on May 9, 2014 for the year ended December 31, 2013, and incorporated herein by reference)
2.4***	Purchase and Sale Agreement dated July 29, 2014 between SM Energy Company and Baytex Energy USA LLC (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 and incorporated herein by reference)
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
3.2	Amended and Restated Bylaws of SM Energy Company, effective as of December 15, 2015 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on December 21, 2015, and incorporated herein by reference)
4.1	Indenture related to the 6.625% Senior Notes due 2019, dated as of February 7, 2011, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on February 10, 2011, and incorporated herein by reference)

4.2	Indenture related to the 6.50% Senior Notes due 2021, dated as of November 8, 2011, by and among SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on November 10, 2011, and incorporated herein by reference)
4.3	Indenture related to the 6.50% Senior Notes due 2023, dated June 29, 2012, between SM Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on July 3, 2012, and incorporated herein by reference)
4.4	Indenture related to the 5.0% Senior Notes due 2024, dated May 20, 2013, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on May 20, 2013, and incorporated herein by reference)
4.5	Indenture related to the 6.125% Senior Notes due 2022, dated November 17, 2014, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on November 18, 2014, and incorporated herein by reference)
4.6	Indenture related to senior debt securities of SM Energy Company by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Registration Statement on Form S-3 filed on May 7, 2015 (Registration No. 333-203936) and incorporated herein by reference)
4.7	2025 Notes Supplemental Indenture (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on May 21, 2015, and incorporated herein by reference)
4.8	2019 Notes Supplemental Indenture (filed as Exhibit 4.3 to the registrant's Current Report on Form 8-K filed on May 21, 2015 and incorporated herein by reference)
10.1†	Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.1 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.2†	Incentive Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.2 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.3	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.4	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.5†	Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.6***	Gas Services Agreement effective as of July 1, 2010 between SM Energy Company and Eagle Ford Gathering LLC (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.7s	Net Profits Interest Bonus Plan, As Amended by the Board of Directors on July 30, 2010 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.8†	Pension Plan for Employees of SM Energy Company as Amended and Restated as of January 1, 2010 (filed as Exhibit 10.30 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.9+	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan as Amended as of November 9, 2010 (filed as Exhibit 10.31 to the registrant's Annual Report on Form 10-K filed for the

year ended December 31, 2010, and incorporated herein by reference)

10.10	Gas Gathering Agreement dated May 31, 2011 between Regency Field Services LLC and SM Energy Company (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.11	Gathering and Natural Gas Services Agreement effective as of April 1, 2011 between SM Energy Company and ETC Texas Pipeline, Ltd. (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.12	Gas Processing Agreement effective as of April 1, 2011 between ETC Texas Pipeline, Ltd. and SM Energy Company (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.13†	Employee Stock Purchase Plan, As Amended and Restated as of June 10, 2011 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.14†	Amendment No. 1 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2011 (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference)
10.15†	Amendment No. 2 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2012 (filed as Exhibit 10.42 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference)
10.16†	Equity Incentive Compensation Plan, As Amended as of May 22, 2013 (filed as Annex A to the registrant's Schedule 14A filed on April 11, 2013, and incorporated herein by reference)
10.17	Fifth Amended and Restated Credit Agreement dated April 12, 2013, among SM Energy Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 15, 2013, and incorporated herein by reference)
10.18†	Form of Performance Stock Unit Award Agreement as of July 31, 2013 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, and incorporated herein by reference)
10.19†	Form of Restricted Stock Unit Award Agreement as of July 31, 2013 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, and incorporated herein by reference)
10.20†	SM Energy Company Non-Qualified Deferred Compensation Plan as of March 10, 2014 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 24, 2014, and incorporated herein by reference)
10.21†	Cash Bonus Plan, As Amended and Restated as of February 1, 2014 (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2013, and incorporated herein by reference)
10.22†	Section 162(m) Cash Bonus Plan, effective as of May 21, 2014 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 28, 2014, and incorporated herein by reference)
10.23*†	Summary of Compensation Arrangements for Non-Employee Directors
10.24	Second Amendment to the Fifth Amended and Restated Credit Agreement dated December 10, 2014, among SM Energy Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 16, 2014, and incorporated herein by reference)
10.25	Third Amendment to Fifth Amended and Restated Credit Agreement, dated May 20, 2015, among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 27, 2015, and incorporated herein by reference)
10.26	Fourth Amendment to Fifth Amended and Restated Credit Agreement, dated October 7, 2015, among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on

October 8, 2015, and incorporated herein by reference)

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10.27	Fifth Amendment to Fifth Amended and Restated Credit Agreement, dated November 11, 2015, among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on November 11, 2015, and incorporated herein by reference)
10.28	Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on October 20, 2015, and incorporated herein by reference)
10.29*†	Amendment No. 3 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2016
10.30***	Amendment to Amended and Restated Gas Gathering Agreement, effective as of September 1, 2015, by and between SM Energy Company and Regency Field Services LLC (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on September 15, 2015, and incorporated herein by reference)
10.31	Amendment to Amended and Restated Gas Gathering Agreement, effective as of February 1, 2016, by and between SM Energy Company and ETC Field Services LLC (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on February 22, 2016, and incorporated herein by reference)
12.1*	Computation of Ratio of Earnings to Fixed Charges
21.1*	Subsidiaries of Registrant
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Ryder Scott Company L.P.
24.1*	Power of Attorney
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
99.1*	Ryder Scott Audit Letter
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

*	Filed with this Form 10-K.
**	Furnished with this Form 10-K.
***	Certain portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934.
†	Exhibit constitutes a management contract or compensatory plan or agreement.
s	Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on July 30, 2010 primarily to reflect the change in the name of the registrant from St. Mary Land & Exploration Company to SM Energy Company. There were no material changes to the substantive terms and conditions in this document.
+	Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on November 9, 2010, in order to make technical revisions to ensure compliance with Section 409A of the Internal Revenue Code. There were no material changes to the substantive terms and conditions in this document.

(c) Financial Statement Schedules. See Item 15(a) above.

SIGNATURES

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

SM ENERGY COMPANY
(Registrant)

Date:	February 24, 2016	By:	/s/ JAVAN D. OTTOSON Javan D. Ottoson President and Chief Executive Officer (Principal Executive Officer)

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Javan D. Ottoson and A. Wade Pursell his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2015, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ JAVAN D. OTTOSON Javan D. Ottoson	President, Chief Executive Officer, and Director (Principal Executive Officer)	February 24, 2016
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2016
/s/ MARK T. SOLOMON Mark T. Solomon	Vice President - Controller and Assistant Secretary (Principal Accounting Officer)	February 24, 2016

Signature	Title	Date
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Chairman of the Board of Directors	February 24, 2016
/s/ LARRY W. BICKLE Larry W. Bickle	Director	February 24, 2016
/s/ STEPHEN R. BRAND Stephen R. Brand	Director	February 24, 2016
/s/ WILLIAM J. GARDINER William J. Gardiner	Director	February 24, 2016
/s/ LOREN M. LEIKER Loren M. Leiker	Director	February 24, 2016
/s/ RAMIRO G. PERU Ramiro G. Peru	Director	February 24, 2016
/s/ JULIO M. QUINTANA Julio M. Quintana	Director	February 24, 2016
/s/ ROSE M. ROBESON Rose M. Robeson	Director	February 24, 2016