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

(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

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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

(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;

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- 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

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