HALLMARK FINANCIAL SERVICES INC
Form 10-Q
August 07, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

Quarterly report pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

For the quarterly period ended June 30, 2018

Commission file number 001-11252

Hallmark Financial Services, Inc.

(Exact name of registrant as specified in its charter)

Nevada	87-0447375
(State or other jurisdiction of Incorporation or organization)	(I.R.S. Employer Identification No.)
777 Main Street, Suite 1000, Fort Worth, Texas (Address of principal executive offices)	76102 (Zip Code)

Registrant's telephone number, including area code: (817) 348-1600

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

Large accelerated filer ¨ Accelerated filer x
Non-accelerated filer ¨ Smaller reporting company ¨ Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 15(a) of the Exchange Act.¨

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: Common Stock, par value $.18 per share – 18,058,676 shares outstanding as of August 7, 2018.

PART I

FINANCIAL INFORMATION

Item 1. Financial Statements

INDEX TO FINANCIAL STATEMENTS

Hallmark Financial Services, Inc. and Subsidiaries

Consolidated Balance Sheets

($ in thousands, except par value)

	June 30, 2018 (unaudited)	December 31, 2017
ASSETS		
Investments:		
Debt securities, available-for-sale, at fair value (cost: $566,520 in 2018 and $604,999 in 2017)	$ 568,826	$ 605,746
Equity securities (cost: $40,308 in 2018 and $30,253 in 2017)	57,914	51,763
Other investments (cost, $3,763 in 2018 and 2017)	3,060	3,824
Total investments	629,800	661,333
Cash and cash equivalents	79,583	64,982
Restricted cash	3,078	2,651
Ceded unearned premiums	127,504	112,323
Premiums receivable	112,188	104,373
Accounts receivable	2,051	1,513
Receivable for securities	3,780	5,235
Reinsurance recoverable	215,045	182,928
Deferred policy acquisition costs	14,058	16,002
Goodwill	44,695	44,695
Intangible assets, net	8,791	10,023
Deferred federal income taxes, net	2,584	1,937
Federal income tax recoverable	-	7,532
Prepaid expenses	2,692	1,743
Other assets	13,431	13,856
Total assets	$ 1,259,280	$ 1,231,126
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities:		
Revolving credit facility payable	$ 30,000	$ 30,000
Subordinated debt securities (less unamortized debt issuance cost of $924 in 2018 and $949 in 2017)	55,778	55,753
Reserves for unpaid losses and loss adjustment expenses	520,552	527,100
Unearned premiums	290,177	276,642
Reinsurance balances payable	65,559	52,487
Current federal income tax payable	187	-
Pension liability	1,470	1,605
Payable for securities	6,706	7,488

Accounts payable and other accrued expenses	31,942	28,933
Total liabilities	$ 1,002,371	$ 980,008
Commitments and Contingencies (Note 17)		
Stockholders' equity:		
Common stock, $.18 par value, authorized 33,333,333; issued 20,872,831 shares in 2018 and 2017	3,757	3,757
Additional paid-in capital	123,017	123,180
Retained earnings	156,585	136,474
Accumulated other comprehensive income	(865)	12,234
Treasury stock (2,814,155 shares in 2018 and 2,703,803 in 2017), at cost	(25,585)	(24,527)
Total stockholders' equity	$ 256,909	$ 251,118
Total liabilities and stockholders' equity	$ 1,259,280	$ 1,231,126

The accompanying notes are an integral part of the consolidated financial statements

Hallmark Financial Services, Inc. and Subsidiaries

Consolidated Statements of Operations

(Unaudited)

($ in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Gross premiums written	$ 173,219	$ 162,056	$ 326,724	$ 297,168
Ceded premiums written	(83,373)	(61,162)	(145,445)	(107,755)
Net premiums written	89,846	100,894	181,279	189,413
Change in unearned premiums	1,132	(10,187)	1,646	(9,483)
Net premiums earned	90,978	90,707	182,925	179,930
Investment income, net of expenses	4,406	4,587	8,846	9,066
Investment gains (losses), net	533	(3,479)	(4,302)	(1,419)
Finance charges	1,161	936	2,201	1,989
Commission and fees	1,032	653	1,735	725
Other income	15	71	61	132
Total revenues	98,125	93,475	191,466	190,423
Losses and loss adjustment expenses	63,648	70,704	127,323	132,546
Other operating expenses	26,360	25,879	53,573	53,374
Interest expense	1,128	1,193	2,155	2,349
Amortization of intangible assets	617	617	1,234	1,234
Total expenses	91,753	98,393	184,285	189,503
Income (loss) before tax	6,372	(4,918)	7,181	920
Income tax expense (benefit)	1,282	(1,568)	1,444	284
Net income (loss)	5,090	(3,350)	5,737	636
Net income (loss) per share:				
Basic	$ 0.28	$ (0.18)	$ 0.32	$ 0.03
Diluted	$ 0.28	$ (0.18)	$ 0.31	$ 0.03

The accompanying notes are an integral part of the consolidated financial statements

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Hallmark Financial Services, Inc. and Subsidiaries

Consolidated Statements of Comprehensive Income

(Unaudited)

($ in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss)	$ 5,090	$ (3,350)	$ 5,737	$ 636
Other comprehensive income :				
Change in net actuarial gain	26	35	53	70
Tax effect on change in net actuarial gain	(5)	(12)	(11)	(24)
Unrealized holding gains arising during the period	1,962	2,654	1,567	7,900
Tax effect on unrealized holding gains arising during the period	(412)	(929)	(329)	(2,765)
Reclassification adjustment for (gains) losses included in net income	(22)	10	(7)	(2,491)
Tax effect on reclassification adjustment for (gains) losses included in net income	5	(3)	2	872
Other comprehensive income, net of tax	1,554	1,755	1,275	3,562
Comprehensive income (loss)	$ 6,644	$ (1,595)	$ 7,012	$ 4,198

The accompanying notes are an integral part of the consolidated financial statements

Hallmark Financial Services, Inc. and Subsidiaries

Consolidated Statements of Stockholders' Equity

(Unaudited)

($ in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Common Stock				
Balance, beginning of period	$3,757	$3,757	$3,757	$3,757
Balance, end of period	3,757	3,757	3,757	3,757
Additional Paid-In Capital				
Balance, beginning of period	123,224	123,183	123,180	123,166
Equity based compensation	(43)	19	1	46
Shares issued under employee benefit plans	(164)	(92)	(164)	(102)
Balance, end of period	123,017	123,110	123,017	123,110
Retained Earnings				
Balance, beginning of period	151,495	152,013	136,474	148,027
Cumulative effect of adoption of updated accounting guidance for equity financial instruments at January 1, 2018	-	-	16,993	-
Reclassification of certain tax effects from accumulated other comprehensive income at January 1, 2018	-	-	(2,619)	-
Net income (loss)	5,090	(3,350)	5,737	636
Balance, end of period	156,585	148,663	156,585	148,663
Accumulated Other Comprehensive Income				
Balance, beginning of period	(2,419)	12,178	12,234	10,371
Cumulative effect of adoption of updated accounting guidance for equity financial instruments at January 1, 2018	-	-	(16,993)	-
Reclassification of certain tax effects from accumulated other comprehensive income at January 1, 2018	-	-	2,619	-
Additional minimum pension liability, net of tax	21	23	42	46
Unrealized holding gains arising during period, net of tax	1,550	1,725	1,238	5,135
Reclassification adjustment for (gains) losses included in net income, net of tax	(17)	7	(5)	(1,619)
Balance, end of period	(865)	13,933	(865)	13,933
Treasury Stock				
Balance, beginning of period	(24,904)	(20,105)	(24,527)	(19,585)
Acquisition of treasury stock	(1,087)	(3,862)	(1,464)	(4,425)

Shares issued under employee benefit plans	406	204	406	247
Balance, end of period	(25,585)	(23,763)	(25,585)	(23,763)
Total Stockholders' Equity	$256,909	$265,700	$256,909	$265,700

The accompanying notes are an integral part of the consolidated financial statements

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Hallmark Financial Services, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

(Unaudited)

($ in thousands)

	Six Months Ended June 30, 2018		2017	
Cash flows from operating activities:				
Net income	$	5,737	$	636
Adjustments to reconcile net income to net cash (used in) provided by operating activities:				
Depreciation and amortization expense		2,479		2,256
Deferred federal income taxes		(988)		(2,174)
Investment losses, net		4,302		1,419
Share-based payments expense		1		46
Change in ceded unearned premiums		(15,181)		(11,156)
Change in premiums receivable		(7,815)		(18,091)
Change in accounts receivable		(538)		513
Change in deferred policy acquisition costs		1,944		(142)
Change in unpaid losses and loss adjustment expenses		(6,548)		23,791
Change in unearned premiums		13,535		20,639
Change in reinsurance recoverable		(32,117)		(16,613)

Change in reinsurance balances payable	13,072	7,690
Change in current federal income tax recoverable/payable	7,719	2,154
Change in all other liabilities	2,899	(745)
Change in all other assets	1,604	2,161
Net cash (used in) provided by operating activities		

2014 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

		Appalachia		Ark-La-Tex			
	Fayetteville Shale	Northeast	Southwest	East Texas	Arkoma Basin	New Ventures	Total
Estimated Proved Reserves:							
Natural Gas (Bcf):							
Developed (Bcf)	3,353	1,594	543	42	141	2	5,675
Undeveloped (Bcf)	1,716	1,598	819		1		4,134
	5,069	3,192	1,362	42	142	2	9,809
Crude Oil (MMBbls):							
Developed (MMBbls)			7.0			0.4	7.4
Undeveloped (MMBbls)			30.2				30.2
			37.2			0.4	37.6
Natural Gas Liquids (MMBbls):							
Developed (MMBbls)			38.5			0.1	38.6
Undeveloped (MMBbls)			80.1				80.1
			118.6			0.1	118.7
Total Proved Reserves (Bcfe)(1):							
Developed (Bcfe)	3,353	1,594	816	42	141	5	5,951
Undeveloped (Bcfe)	1,716	1,598	1,481		1		4,796
	5,069	3,192	2,297	42	142	5	10,747
Percent of Total	47%	30%	22%		1%		100%
Percent Proved Developed	66%	50%	36%	100%	99%	100%	55%
Percent Proved Undeveloped	34%	50%	64%		1%		45%
Production (Bcfe)	494	254	3	5	10	2	768

Capital Investments (millions)(2)	$944	$695	$ 5,012	$2	$3	$493	$7,149
Total Gross Producing Wells(3)	4,027	522	1,034	153	1,138	13	6,887
Total Net Producing Wells(3)	2,777	257	800	94	556	10	4,494
Total Net Acreage	764,287 (4)	266,073 (5)	413,376 (6)	48,292 (7)	228,789 (8)	4,181,044 (9)	5,901,861
Net Undeveloped Acreage	267,456 (4)	205,491 (5)	188,244 (6)	64 (7)	45,425 (8)	4,170,687 (9)	4,877,367
PV-10:							
Pre-tax (millions)(10)	$5,250	$2,120	$ 1,859	$55	$175	$(1)	$9,458
PV of taxes (millions)(10)	1,063	429	376	11	36		1,915
After-tax (millions)(10)	$4,187	$1,691	$ 1,483	$44	$139	$(1)	$7,543
Percent of Total	55%	22%	20%	1%	2%		100%
Percent Operated(11)	97%	98%	98%	97%	87%	100%	97%

(1) We have no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. We used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

(2) Our Total and Fayetteville Shale capital investments exclude $105 million related to our drilling rig related equipment, sand facility and other equipment.

(3) Represents all producing wells, including wells in which we only have an overriding royalty interest, as of December 31, 2014.

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(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 15,289 net acres in 2015, 921 net acres in 2016, and 779 net acres in 2017 (excluding 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management).

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 35,215 net acres in 2015, 28,912 net acres in 2016 and 69,497 net acres in 2017.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 46,342 net acres in 2015, 41,184 net acres in 2016 and 44,256 net acres in 2017. Of this acreage, 16,876 net acres in 2015, 17,798 net acres in 2016 and 15,691 net acres in 2017 can be extended for an average of an additional 4.6 years.

(7) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 64 net acres in 2015, zero net acres in 2016 and zero net acres in 2017.

(8) Includes 123,442 net developed acres and 432 net undeveloped acres in the Arkoma Basin that are also within our Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above. Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 15,332 net acres in 2015, 5,533 net acres in 2016 and 986 net acres in 2017.

(9) Assuming successful wells are not drilled to develop the acreage and leases are not extended, our leasehold expiring over the next three years, excluding New Brunswick, Canada, the Lower Smackover Brown Dense area and the Sand Wash Basin will be 143,109 net acres in 2015, 302,688 net acres in 2016 and 221,189 net acres in 2017. With regard to our acreage in New Brunswick, Canada, 2,518,518 net acres are scheduled to expire in March 2015. In February 2015, we requested an extension of our license agreement. With regard to our acreage in the LSBD, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 153,866 net acres in 2015, 60,078 net acres in 2016 and 17,057 net acres in 2017. With regard to our acreage in the Sand Wash Basin, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 107,963 net acres in 2015, 85,977 net acres in 2016, and 34,970 net acres in 2017.

(10) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company s proved reserves that we believe is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved natural gas and oil reserves.

(11) Based upon pre-tax PV-10 of proved developed producing activities.

We refer you to Note 4 in our consolidated financial statements for a more detailed discussion of our proved natural gas and oil reserves as well as our standardized measure of discounted future net cash flows related to our proved natural gas and oil reserves. We also refer you to the risk factor Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate in Item 1A of Part I of this Annual Report and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

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Proved Undeveloped Reserves

Presented below is a summary of changes in our proved undeveloped reserves for 2012, 2013 and 2014.

Changes in Proved Undeveloped Reserves (Bcfe)

		Appalachia		Ark-La-Tex		
	Fayetteville Shale	Northeast	Southwest	East Texas	Arkoma Basin	Total
December 31, 2011	2,415	170		27	21	2,633
Extensions, discoveries and other additions	32	305				337
Total revision attributable to performance and production	(239)	16				(223)
Price revisions	(1,401)	1		(26)	(7)	(1,433)
Developed	(443)	(50)				(493)
Disposition of reserves in place						
Acquisition of reserves in place						
December 31, 2012	364	442		1	14	821
Extensions, discoveries and other additions (1)	1,530	810				2,340
Total revision attributable to performance and production	(115)	(33)			(9)	(157)
Price revisions	18	26		1		45
Developed	(142)	(170)				(312)
Disposition of reserves in place						
Acquisition of reserves in place						
December 31, 2013	1,655	1,075		2	5	2,737
Extensions, discoveries and other additions (2)	573	589				1,162
Total revision attributable to performance and production (3)	(130)	307		(2)	(4)	171
Price revisions	24	11				35
Developed	(406)	(384)				(790)
Disposition of reserves in place						
Acquisition of reserves in place (4)			1,481			1,481
December 31, 2014	1,716	1,598	1,481		1	4,796

(1) The 2013 proved undeveloped reserve additions are primarily associated with the increase in gas prices.
(2) Primarily associated with the undeveloped locations that were added throughout the year in 2014 due to our successful drilling program.
(3) Primarily due to changes associated with the analysis of updated data collected in the year and decreases related to current year production.
(4) Our acquisition of reserves in place is attributable to the purchase of undeveloped locations in West Virginia and southwest Pennsylvania.

As of December 31, 2014, we had 4,796 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2014, we invested $767 million in connection with converting 790 Bcfe or 29% of our proved undeveloped reserves as of December 31, 2013, into proved developed reserves and added 2,643 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale and the Appalachian Basin. As of December 31, 2013, we had 2,737 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2013, we invested $248 million in connection with converting 312 Bcfe, or 38%, of our proved undeveloped reserves as of December 31, 2012 into proved developed reserves and added 2,340 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale and the Appalachian Basin. Our December 31, 2014 proved reserves include 181 Bcfe of proved undeveloped reserves from 60 locations that have a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties have a negative present value of $28 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves.

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The development of our proved undeveloped reserves will require us to make significant additional investments. We expect that the development costs for our proved undeveloped reserves of 4,796 Bcfe as of December 31, 2014 will require us to invest an additional $4.9 billion for those reserves to be brought to production. Our ability to make the necessary investments to generate these cash inflows is subject to factors that may be beyond our control. A significant decrease in price levels for an extended period of time could result in certain reserves no longer being economic to produce, leading to both lower proved reserves and cash flows. We refer you to the risk factors A substantial or extended decline in natural gas and oil prices would have a material adverse effect on us, We may have difficulty financing our planned capital investments, which could adversely affect our growth and Our level of indebtedness and the terms of our financing arrangements may adversely affect operations and limit our growth in Item 1A of Part I of this Annual Report and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Reserve Replacement

The reserve replacement ratio measures the ability of an exploration and production company to add new reserves to replace the reserves that are being depleted by its current production volumes. The reserve replacement ratio, which we discuss below, is an important analytical measure used by investors and peers in the E&P industry to evaluate performance results and long-term prospects. There are limitations as to the usefulness of this measure, as it does not reflect the type of reserves or the cost of adding the reserves or indicate the potential value of the reserve additions.

In 2014, we replaced 591% of our production volumes with 1,693 Bcfe of proved reserve additions, net upward revisions of 543 Bcfe, and 2,304 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 531 Bcfe were proved developed and 1,162 Bcfe were proved undeveloped. In 2014, upward reserve revisions resulting from higher gas prices totaled 38 Bcf, 10 Bcf and 6 Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. We also had performance revisions in 2014 of (126) Bcf, 636 Bcf and (21) Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. Additionally, our reserves increased by 2,304 Bcfe in 2014 as a result of acquisitions primarily associated with acreage in Southwest Appalachia.

In 2013, we replaced 550% of our production volumes with 3,285 Bcfe of proved reserve additions, net upward revisions of 326 Bcfe, and 4 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 945 Bcfe were proved developed and 2,340 Bcfe were proved undeveloped. In 2013, upward reserve revisions resulting from higher gas prices totaled 191 Bcf, 35 Bcf and 21 Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. We also had upward performance revisions in 2013 of 16 Bcf, 62 Bcf and 1 Bcf in our Fayetteville Shale, Northeast Appalachia and New Ventures divisions, respectively. Additionally, our reserves increased by 4 Bcf in 2013 as a result of our acquisition of natural gas leases and wells.

In 2012, we replaced our production volumes with 920 Bcfe of proved reserve additions as a result of our drilling and acquisition program but also incurred net downward revisions of 2,088 Bcfe principally due to a decrease in the price of natural gas and to a lesser extent due to downward performance revisions of 336 Bcfe. Of the reserve additions, 583 Bcfe were proved developed and 337 Bcfe were proved undeveloped. The total downward reserve revisions were primarily impacted by the low commodity price environment in 2012 and to a lesser extent by downward performance revisions. In 2012, downward reserve revisions resulting from lower gas prices totaled 1,684 Bcf, 9 Bcf and 59 Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. We also had a net downward performance revision in 2012 of 362 Bcf and 10 Bcf in our Fayetteville Shale and Ark-La-Tex divisions, respectively. We had a net upward performance revision in 2012 of 36 Bcf in Northeast Appalachia. Additionally, our reserves decreased by 141 Bcfe in 2012 as a result of our disposition of natural gas leases and wells.

For the period ended December 31, 2014, our three-year average reserve replacement ratio, including revisions and acquisitions, was 351%. Our reserve replacement ratio for 2014, excluding reserve revisions, was 520%, compared to 501% in 2013 and 163% in 2012. Excluding reserve revisions and acquisitions, our three-year average reserve replacement ratio was 296%.

Since 2005, the substantial majority of our reserve additions have been generated from our Fayetteville Shale division. However, over the past several years, Northeast Appalachia has also contributed to an increasing amount of our reserve additions, totaling 836 Bcf, 1,200 Bcf and 500 Bcf in 2014, 2013 and 2012, respectively. Additionally, our reserves increased by 2,304 Bcfe in 2014 as a result of acquisitions primarily associated with acreage in Southwest Appalachia. We expect our drilling programs in the Fayetteville Shale, Northeast Appalachia, and Southwest Appalachia to continue to be the primary source of our reserve additions in the future; however, our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors Our drilling plans are subject to change and Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns in Item 1A of Part I of this Annual Report and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Operations

Fayetteville Shale

Our Fayetteville Shale properties are one of the primary focus areas of our exploration and production business. The Fayetteville Shale is a Mississippian-age unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, ranging in thickness from 50 to 550 feet and ranging in depth from 1,500 to 6,500 feet. As of December 31, 2014, we held leases for approximately 888,161 net acres in the play area (267,456 net undeveloped acres, 496,831 net developed acres held by Fayetteville Shale production, 123,442 net acres held by conventional production in the Arkoma Basin, and 432 net undeveloped acres in the Arkoma Basin), compared to approximately 905,684 net acres at year-end 2013 and 913,502 net acres at year-end 2012.

Approximately 5,069 Bcf of our reserves at year-end 2014 were attributable to our Fayetteville Shale properties, compared to approximately 4,795 Bcf at year-end 2013 and 2,988 Bcf at year-end 2012. Our reserves in the Fayetteville Shale increased by 274 Bcf in 2014, which included reserve additions of 856 Bcf, net upward price revisions of 38 Bcf, 126 Bcf of net downward revisions due to well performance, offset by production of 494 Bcf. Our net production from the Fayetteville Shale was 494 Bcf in 2014, compared to 486 Bcf in both 2013 and 2012. In 2015, we estimate our net production from the Fayetteville Shale will be in the range of 448 to 453 Bcf.

At year-end 2014, after excluding our acreage in the conventional Arkoma Basin and the federal acreage we hold in the Ozark Highlands Unit, approximately 85% of our 580,060 total net leasehold acres remaining in the Fayetteville Shale was held by production. For more information about our acreage and well count, we refer you to Properties in Item 2 of Part 1 of this Annual Report. Excluding our acreage in the conventional Arkoma Basin, our acreage position was obtained at an average cost of approximately $320 per acre and has an average royalty interest of 15%. In 2015, we expect to earn 4 sections, or approximately 1,422 net acres, representing 1% of our drilling program. As of December 31, 2014, excluding our acreage in the conventional Arkoma Basin and our federal acreage, the undeveloped portion of our acreage had an average remaining lease term of 6 months. We refer you to the risk factor If we fail to drill all of the wells that are necessary to hold our acreage, the initial lease terms could expire, which would result in the loss of certain leasehold rights in Item 1A of Part I of this Annual Report.

Following the commencement of two court actions, now consolidated, alleging deficiencies in the Environmental Impact Statement issued in connection with the grant of the leases by the Bureau of Land Management (BLM) in the Ozark National Forest, the BLM has discontinued approval of operational permits in the forest, including permits to drill, pending resolution of the litigation. The Ozark Highlands Unit lies entirely within the Ozark National Forest. Although the Company is not a party to the litigation and the plaintiffs complaints do not seek invalidation of the leases, we currently are unable to obtain permits to drill on the 158,231 acres we have leased in the unit and the national forest.

As of December 31, 2014, we had spud a total of 4,578 wells in the Fayetteville Shale since its commencement in 2004, of which 4,002 were operated by us and 576 were outside-operated wells. Of these wells, 468 were spud in 2014, 527 in 2013 and 491 in 2012. All of the wells spud in 2014 were designated as horizontal wells. At year-end 2014, 3,742 wells operated by the Company had been drilled and completed overall, including 3,651 horizontal wells. Of the 3,651 horizontal wells, 3,633 wells were fracture stimulated using either slickwater or crosslinked gel stimulation treatments, or a combination thereof.

In 2014, the horizontal wells we drilled as operator had an average completed well cost of $2.6 million per well, average horizontal lateral length of 5,440 feet, and an average time to drill to total depth of 6.8 days from re-entry to re-entry, which includes the downtime associated with the delivery and operational start up of seven new rigs which are expected to decrease drilling times in 2015 and beyond as the technological enhancements on these rigs is utilized. This compares to an average completed operated well cost of $2.4 million per well, average horizontal lateral length of 5,356 feet and average time to drill to total depth of 6.2 days from re-entry to re-entry during 2013. In 2012, our average completed operated well cost was $2.5 million per well with an average horizontal lateral length of 4,833 feet and average time to drill to total depth of 6.7 days from re-entry to re-entry. The operated wells we placed on production during 2014 averaged initial production rates of 4,430 Mcf per day, compared to average initial production rates of 4,041 Mcf per day in 2013 and 3,629 Mcf per day in 2012. In 2014 and 2013, our initial production rates increased compared to 2013 and 2012, respectively, as a result of longer lateral lengths, improved well bore placement, and further refined completion and flowback techniques. During 2014, we placed 145 operated wells on production with initial production rates that exceeded 5.0 MMcf per day, compared to 93 wells in 2013 and 59 wells in 2012.

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Our total proved net reserves in the Fayetteville Shale at year-end 2014 were from a total of 5,445 locations, of which 4,045 were proved developed producing, 187 were proved developed non-producing and 1,213 were proved undeveloped. Of the 5,445 locations, 5,373 were horizontal. The average gross proved reserves for the undeveloped wells included at year-end 2014 was approximately 2.3 Bcf per well, compared to 2.5 Bcf per well at year-end 2013, and 2.8 Bcf per well at year-end 2012. The decrease in average gross proved reserves for our undeveloped wells in 2014 was primarily due to the addition of proven undeveloped locations in areas of the field with lower estimated ultimate recoveries. The decrease in average gross proved reserves for our undeveloped wells in 2013 was primarily due to the addition of over 800 proven undeveloped locations with lower estimated ultimate recoveries that were added due to the higher gas price environment. Total proved net natural gas reserves in the Fayetteville Shale in 2013 were approximately 4,795 Bcf from a total of 4,631 locations, of which 3,511 were proved developed producing, 59 were proved developed non-producing and 1,061 were proved undeveloped. Total proved net natural gas reserves in the Fayetteville Shale in 2012 totaled approximately 2,988 Bcf from a total of 3,508 locations, of which 3,175 were proved developed producing, 123 were proved developed non-producing and 210 were proved undeveloped.

In 2014, we invested approximately $944 million in the Fayetteville Shale, which included approximately $838 million to spud 468 wells, 464 of which we operate. Included in our total capital investments in the Fayetteville Shale during 2014 was $99 million in capitalized costs and other expenses and $7 million for acquisition of properties. In 2013, we invested approximately $907 million in the Fayetteville Shale, which included $804 million to spud 527 wells, 504 of which we operate, $97 million in capitalized costs and other expenses and $6 million for acquisition of properties. In 2012, we invested approximately $991 million in the Fayetteville Shale, which included $877 million to spud 491 wells, 453 of which we operate, $110 million in capitalized costs and other expenses and $4 million for acquisition of properties. As of December 31, 2014, we had acquired approximately 1,324 square miles of 3-D seismic data, which provides us with seismic data on approximately 65% of our net acreage position in the Fayetteville Shale, excluding our acreage in the Arkoma Basin.

In 2015, we plan to invest approximately $560 million in our Fayetteville Shale properties, which includes participating in approximately 225 to 235 gross wells, all of which we plan to operate.

We believe that our Fayetteville Shale acreage continues to have significant development potential. Our strategy is to continue our development drilling, increase the amount of acreage we hold by production and determine the economic viability of the undrilled portion of our acreage. Our drilling program with respect to our Fayetteville Shale properties is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods and well spacing, the extent to which we can replicate the results of our most successful Fayetteville Shale wells in other Fayetteville Shale acreage and the natural gas commodity price environment. As we continue to gather data about the Fayetteville Shale, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor Our drilling plans are subject to change in Item 1A of Part I of this Annual Report.

Northeast Appalachia

We began leasing acreage in northeastern Pennsylvania in 2007 in an effort to participate in the emerging Marcellus Shale. As of December 31, 2014, we had approximately 266,073 net acres in Northeast Appalachia under which we believe the Marcellus Shale is present (205,491 net undeveloped acres and 60,582 net developed acres held by production), compared to approximately 292,446 net acres at year-end 2013 and 176,298 net acres at year-end 2012. Our undeveloped acreage position as of December 31, 2014 had an average remaining lease term of 2.5 years and an average royalty interest of 15% and was obtained at an average cost of approximately $1,189 per acre. In January 2015, we closed on an agreement to purchase certain oil and gas assets covering approximately 46,700 net acres in northeast Pennsylvania from WPX for $288 million, subject to customary post-closing adjustments. At closing, this acreage was producing approximately 50 million net cubic feet of gas per day from 63 operated horizontal wells. In connection with this acquisition, we assumed firm transportation capacity of 260 million cubic feet of gas per day predominantly on the Millennium pipeline. The acquired acreage is near our existing acreage in Northeast Appalachia.

As of December 31, 2014, we had spud 376 operated wells, 255 of which were on production and 367 of which are horizontal wells. In 2014, we invested approximately $695 million in Northeast Appalachia and spud 99 operated horizontal wells and acquired 5 horizontal and 2 vertical wells, resulting in reserve additions and revisions of 1,483 Bcf. Our reserves in Northeast Appalachia increased by 1,229 Bcf in 2014, which included reserve additions of 834 Bcf, 636 Bcf of net upward revisions due to well performance, net upward price revisions of 10 Bcf, and acquisitions of 2 Bcf, offset by production of 254 Bcf. Of the 104 horizontal wells, 61 wells are located in Susquehanna County, 32 wells are located in Bradford County, 4 wells are located in Lycoming County, 3 wells are located in Tioga County, 3 wells are located in Wyoming County and the remaining 1 well is located in Sullivan County. In 2014, our operated horizontal wells had an average completed well cost of $6.1 million per well, average horizontal lateral length of 4,752 feet and an average of 15 fracture stimulation stages. This compares to an average completed operated well cost of $7.0 million per well, average horizontal lateral length of 4,982 feet and an average of 18 fracture stimulation stages in 2013. In 2012, our average completed operated well cost was $6.1 million per well with an average horizontal lateral length of 4,070 feet and an average of 12 fracture stimulation stages. Included in our total capital investments in Northeast Appalachia during 2014 was approximately $571 million for drilling and completions, $28 million for acquisition of properties, $25 million for seismic and $71 million in facilities, capitalized costs and other expenses. In 2013, we invested approximately $872 million in Northeast Appalachia and spud 108 operated wells, resulting in reserve additions and revisions of 1,297 Bcf. In 2012, we invested approximately $507 million in Northeast Appalachia and spud 92 operated wells, resulting in net reserve additions and revisions of 500 Bcf.

Approximately 3,192 Bcf of our total proved net reserves at year-end 2014 were attributable to Northeast Appalachia. We had a total of 254 horizontal and one vertical well that we operated and that were on production as of December 31, 2014, resulting in net production from this area of 254 Bcf in 2014, compared to 151 Bcf in 2013 and 54 Bcf in 2012. Our 2014 year-end reserves in Northeast Appalachia include a total of 737 locations, of which 524 were proved developed producing, 13 were proved developed non-producing and 200 were proved undeveloped. At year-end 2013, we had approximately 1,963 Bcf in proved reserves in Northeast Appalachia from a total of 522 locations, of which 333 were proved developed producing, and 189 were proved undeveloped. At year-end 2012, we had approximately 816 Bcf of proved reserves in Northeast Appalachia from a total of 203 locations, of which 129 were proved developed producing, 1 was proved developed non-producing and 73 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in our year-end reserves for 2014 was approximately 9.6 Bcf per well, compared to 6.9 Bcf per well at year-end 2013 and 7.6 Bcf per well in 2012.

In 2015, we plan to invest approximately $700 million in Northeast Appalachia (excluding the purchase price for the additional 46,700 net acres in the WPX Acquisition) and expect to participate in a total of 88 to 92 gross wells in 2015, the vast majority of which will be operated by us. In 2015, we estimate our net production from Northeast Appalachia will be in the range of 356 to 361 Bcf. Our ability to bring our Northeast Appalachia production to market will depend on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to Midstream Services in Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Northeast Appalachia production and to the risk factor Our ability to sell our natural gas and oil and to receive market prices for our production may be adversely affected by constraints or interruptions on gathering systems, pipelines, processing and transportation systems owned or operated by us or others. in Item 1A of Part I of this Annual Report.

We believe that our Northeast Appalachia acreage has significant development potential. Our drilling program with respect to Northeast Appalachia is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods, transportation capacity and well spacing and the natural gas commodity price environment. As we continue to gather data about Northeast Appalachia, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor Our drilling plans are subject to change in Item 1A of Part I of this Annual Report.

Southwest Appalachia

In December 2014, we closed a transaction to acquire oil and gas assets in West Virginia and southwest Pennsylvania for approximately $5.0 billion. This acreage has at least three drilling objectives, namely the Marcellus, Utica and Upper Devonian Shales. As of December 31, 2014, we had approximately 413,376 net acres in Southwest Appalachia (188,244 net undeveloped acres and 225,132 net developed acres held by production). Our undeveloped acreage position as of December 31, 2014 had an average remaining lease term of 3 years and an average net revenue interest of 86%.

Approximately 2,297 Bcfe of our total proved net reserves at year-end 2014 were attributable to Southwest Appalachia. These proved reserves are substantially attributable to the Marcellus Shale (2,260 Bcfe) with the remaining difference attributable to the Utica Shale and shallower reservoirs associated with historic vertical wells. We had a total of 255 horizontal and 667 vertical wells that we operated and that were on production as of December 31, 2014. Additionally, there were 42 horizontal wells in progress at the end of 2014. Our 2014 year-end reserves in Southwest Appalachia include a total of 1,502 locations, of which 1,034 were proved developed producing, 124 were proved developed non-producing and 344 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in our year-end reserves for 2014 was approximately 8.4 Bcfe per well.

In 2015, we plan to invest approximately $520 million in Southwest Appalachia (excluding the purchase price for the additional 30,000 net acres in the Statoil Property Acquisition) and expect to participate in a total of 50 to 55 gross wells in

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2015, most of which will be operated by us. In 2015, we estimate our net production from Southwest Appalachia will be in the range of 136 to 141 Bcfe. Our ability to bring our Southwest Appalachia production to market will depend on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to Midstream Services within Item1 of this Annual Report for a discussion of our gathering and transportation arrangements for Southwest Appalachia production and to the risk factor Our ability to sell our natural gas and oil and to receive market prices for our production may be adversely affected by constraints or interruptions on gathering systems, pipelines, processing and transportation systems owned or operated by us or others. in Item 1A of Part I of this Annual Report.

We believe that our Southwest Appalachia acreage has significant development potential. Our drilling program with respect to Southwest Appalachia is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods, transportation capacity and well spacing and the natural gas commodity price environment. As we continue to gather data about Southwest Appalachia, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor Our drilling plans are subject to change in Item 1A of Part I of this Annual Report.

New Ventures

We actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as New Ventures. We have been focusing on both natural gas and oil unconventional plays, and the technological methods best suited to developing these plays, such as horizontal drilling and fracture stimulation techniques. New Ventures prospects are evaluated based on multi-well potential and land availability as well as other criteria and may be located both inside and outside of the United States. As of December 31, 2014, we held 4,170,687 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres were located in New Brunswick, Canada. This compares to 3,972,732 net undeveloped acres held at year-end 2013 and 3,819,128 net undeveloped acres held at year-end 2012.

Although we believe that our New Ventures projects have significant exploration and exploitation potential, there can be no assurance that any prospects will result in viable projects or that we will not abandon our initial investments. We refer you to the risk factors The success of our New Ventures projects is subject to drilling and completion technique risks and enhanced recovery methods. Our drilling results may not meet our expectations for reserves or production and the value of our undeveloped New Venture acreage could decline, and Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns in Item 1A of Part I of this Annual Report.

Sand Wash Basin. In 2014, we acquired approximately 376,497 net acres in northwest Colorado targeting crude oil, NGLs and natural gas contained in the Sand Wash Basin. Testing of the play commenced in the second half of the year with us drilling four vertical wells and one horizontal well. Results have been encouraging to date and we intend to continue to test the play in 2015.

Brown Dense. In July 2011, we announced that we would begin testing a new unconventional liquids rich play targeting the Brown Dense formation, an unconventional reservoir that ranges in vertical depths from 8,000 to 11,000 feet and appears to be laterally extensive over a large area ranging in thickness from 300 to 550 feet. As of December 31, 2014, we held approximately 304,371 net acres in the area, obtained at an average cost of $831 per acre. Our leases currently have an approximate 81% average net revenue interest and an average primary lease term of approximately three years, which may be extended for approximately three to four additional years.

As of December 31, 2014, we had drilled 14 operated wells in the area, 6 of which were currently producing. Late in 2014, the Company acquired 75 miles of 3-D seismic data and is currently in the process of analyzing that data and our results to date.

New Brunswick, Canada. In March 2010, we successfully bid for exclusive licenses from the Department of Natural Resources of New Brunswick to search and conduct an exploration program covering 2,518,518 net acres in the province in order to test new hydrocarbon basins. As a condition under our licenses, we are required to make investments of approximately $47 million Canadian dollars in the province by March 2015. In order to obtain the licenses, we provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $45 million Canadian dollars. The promissory notes secure our capital expenditure obligations under the licenses and are returnable to us to the extent we perform such obligations. If we fail to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. Through December 31, 2014, we have invested approximately $45 million Canadian dollars, or $44 million USD, in our New Brunswick exploration program toward our commitment, fully covering the promissory notes held by the Province of New Brunswick.

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Our licenses are scheduled to expire in March 2015. The newly elected provincial government in New Brunswick recently announced an intent to impose a moratorium on hydraulic fracturing until a list of conditions is met and has introduced authorizing legislation in the provincial legislature. We have applied for an extension of our licenses past the end of the moratorium, but as of this time that extension has not been granted. The list of conditions that the provincial government has announced is subjective, and we cannot predict the duration of the moratorium or whether we will be granted the extension requested or any other extension. Unless and until the moratorium is lifted and our licenses are extended, we will not be able to continue with our program in New Brunswick. If this extension is not granted, we may be required to write off our investment.

Acquisitions

In December 2014, we acquired approximately 413,000 net acres in West Virginia and southwest Pennsylvania with plans to target the Marcellus, Utica and Upper Devonian Shales for approximately $5.0 billion. Additionally, in January 2015, we acquired an additional approximate 30,000 net acres in this area for $365 million.

Also, in January 2015, we acquired approximately 46,700 net acres in northeast Pennsylvania for $288 million. As part of this transaction, we also received firm transportation capacity of 260 million cubic feet per day predominately on the Millennium pipeline.

In March 2014 and July 2014, we acquired approximately 380,000 net acres in northwest Colorado principally in the Sand Wash basin for approximately $215 million.

In April 2013, we acquired approximately 162,000 net acres in Northeast Appalachia for approximately $82 million. The acquired acreage is near our existing acreage in Northeast Appalachia.

Capital Investments

During 2014, we invested a total of approximately $7.3 billion in our E&P business and participated in drilling 576 wells, 280 of which were successful and 296 of which were in progress at year-end. Of the 296 wells in progress at year-end, 224 and 71 were located in our Fayetteville Shale and Northeast Appalachia operating areas, respectively. Additionally, we had 42 wells in progress in Southwest Appalachia at the end of 2014. Of the approximately $7.3 billion invested in our E&P business in 2014, approximately $944 million was invested in the Fayetteville Shale, $695 million in Northeast Appalachia, $5.0 billion in Southwest Appalachia, $2 million in East Texas, $3 million in our conventional Arkoma Basin program and $493 million in New Ventures projects, which includes $115 million in the Brown Dense and $288 million in the Sand Wash Basin.

Of the $7.3 billion invested in 2014, approximately $1.5 billion was invested in exploratory and development drilling and workovers, $5.3 billion for acquisition of properties, $247 million in capitalized interest and other expenses and $56 million for seismic expenditures. Additionally, we invested approximately $105 million in our drilling rigs and related equipment, sand facility and other equipment, and $5 million in pond and water facilities. In 2013, we invested approximately $2.1 billion in our primary E&P business activities and participated in drilling 653 wells. Of the $2.1 billion invested in 2013, approximately $1.5 billion was invested in exploratory and development drilling and workovers, $224 million in capitalized interest and other expenses, $159 million for acquisition of properties, and $28 million for seismic expenditures. Additionally, we invested approximately $76 million in our drilling rigs and related equipment, sand facility and other equipment, and $18 million in pond and water facilities. In 2012, we invested approximately $1.9 billion in our primary E&P business activities and participated in drilling 595 wells. Of the $1.9 billion invested in 2012, approximately $1.4 billion was invested in exploratory and development drilling and workovers, $186 million for acquisition of properties, $10 million for seismic expenditures and $254 million in capitalized interest and other expenses. Additionally, we invested approximately $15 million in our drilling rig related equipment, sand facility and other equipment.

In 2015, excluding the capital associated with the closing of the WPX and Statoil Property Acquisitions, we plan to invest approximately $1.9 billion in our E&P program and participate in drilling 363 to 382 gross wells, the vast majority of which will be operated by us. The Fayetteville Shale, Northeast Appalachia and Southwest Appalachia will be the primary focus of our capital investments, with planned investments of approximately $560, $700, and $520 million, respectively. Our planned 2015 capital investments also include approximately $110 million in the Sand Wash Basin, the Brown Dense and other New Ventures projects.

Of the $1.9 billion allocated to our 2015 E&P capital budget, approximately $1.4 billion currently is planned to be invested in development and exploratory drilling, $17 million in seismic and other geological and geophysical expenditures, $72 million in acquisition of properties and $391 million in capitalized interest and expenses as well as equipment, facilities and technology-related expenditures. Additionally, we plan to invest $31 million in our E&P services which support our E&P operations. The planned capital program for 2015 is flexible and can be modified. We will

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reevaluate our proposed investments as needed to take into account prevailing market conditions and, if natural gas prices are challenged in 2015, we could change our planned investments. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Investments within Item 7 of Part II of this Annual Report for additional discussion of the factors that could impact our planned capital investments in 2015.

Sales, Delivery Commitments and Customers

Sales. Our daily natural gas equivalent production averaged 2,105 MMcfe in 2014, compared to 1,800 MMcfe in 2013 and 1,544 MMcfe in 2012. Total natural gas equivalent production was 768 Bcfe in 2014, up from 657 Bcfe in 2013 and 565 Bcfe in 2012. Our natural gas production was 766 Bcf in 2014, compared to 656 Bcf in 2013 and 565 Bcf in 2012. The increase in production in 2014 resulted primarily from a 103 Bcf increase in net production from our Northeast Appalachia properties, a 3 Bcfe increase in net production from our Southwest Appalachia properties, and an 8 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a combined 3 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The increase in production in 2013 resulted primarily from a 97 Bcf increase in net production from our Northeast Appalachia properties, a 1 Bcfe increase in net production from our New Ventures properties, and a 1 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a combined 7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. We produced 235,000 barrels of oil in 2014, compared to 138,000 barrels of oil in 2013 and 83,000 barrels of oil in 2012. Our oil production has increased between 2014 and 2013 primarily due to the acquisition of oil and gas properties in Southwest Appalachia and our exploration activities in the Brown Dense. In 2014, we produced 231,000 barrels of NGLs, compared to 50,000 barrels of NGLs in 2013, primarily due to the acquisition of oil and gas properties in West Virginia and our exploration activities in the Brown Dense. For 2015, we are targeting total net natural gas, oil and NGL production of approximately 940 to 955 Bcfe, which represents a growth rate of approximately 23% over our 2014 production volumes, using midpoints.

Sales of natural gas and oil production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand for our production. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas production to support certain desired levels of cash flow and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. As of December 31, 2014, we had New York Mercantile Exchange, or NYMEX, commodity price hedges in place on 240 Bcf, or approximately 27% of our targeted 2015 natural gas production. We intend to hedge additional future production volumes to the extent natural gas prices rise to levels that we believe will achieve certain desired levels of cash flow. We refer you to Item 7A of this Annual Report, Quantitative and Qualitative Disclosures about Market Risks, for further information regarding our hedge position as of December 31, 2014.

Including the effect of hedges, we realized an average wellhead price of $3.72 per Mcf for our natural gas production in 2014, compared to $3.65 per Mcf in 2013 and $3.44 per Mcf in 2012. Our hedging activities decreased our average realized natural gas sales price by $0.02 per Mcf in 2014, compared to increases of $0.48 per Mcf in 2013 and $1.10 per Mcf in 2012. Our average oil price realized was $79.91 per barrel in 2014, compared to $103.32 per barrel in 2013 and $101.54 per barrel in 2012. Our average realized NGL price was $15.72 per barrel in 2014 compared to $43.63 per barrel in 2013. None of our oil or NGL production was hedged during 2014, 2013 or 2012.

During 2014, the average price received for our natural gas production, excluding the impact of hedges, was approximately $0.67 per Mcf lower than average NYMEX prices. Differences between NYMEX and price realized are due primarily to locational differences and transportation cost. Assuming a NYMEX commodity price for 2015 of $3.25 per Mcf of natural gas, we expect to receive an average sales price for our natural gas production $0.70 to $0.85

per Mcf below the NYMEX Henry Hub average monthly settlement price, including the impact of financial basis hedges. This discount to NYMEX includes average third-party transportation charges in the range of $0.35 to $0.40 per Mcf and average fuel charges in the range of .50% to 1.0% of our sales price for natural gas and basis differential. As of December 31, 2014, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 292 Bcf and 139 Bcf of our 2015 and 2016 production, respectively, and expected natural gas production through financial hedging activities and physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.13) per Mcf and ($0.08) per Mcf for 2015 and 2016, respectively.

Delivery Commitments. As of December 31, 2014, we had natural gas delivery commitments of 452 Bcf in 2015 and 194 Bcf in 2016 under existing agreements. These amounts are well below our forecasted 2015 natural gas production of approximately 875 to 890 Bcf from our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia divisions and anticipated 2016 production from our available reserves in our Fayetteville Shale, Northeast Appalachia and Southwest

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Appalachia divisions, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our contractual obligations other than those discussed in Item 1A. Risk Factors of Part I of this Annual Report. We expect to be able to fulfill all of our short-term or long-term contractual obligations to provide natural gas from our own production of available reserves; however, if we are unable to do so, we may have to purchase natural gas at market to fulfill our obligations.

Customers. Our customers include major energy companies, utilities and industrial purchasers of natural gas. During the years ended December 31, 2014, 2013 and 2012, no single third-party purchaser accounted for 10% or more of our consolidated revenues.

Competition

All phases of the natural gas and oil industry are highly competitive. We compete in the acquisition of properties, the search for and development of reserves, the production and sale of natural gas and oil and the securing of labor and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies and individual producers and operators. Many of these competitors have financial and other resources that substantially exceed those available to us.

Competition in Arkansas has increased in recent years due largely to the development of improved access to interstate pipelines and our discovery of the Fayetteville Shale. Although improved intrastate and interstate pipeline transportation in Arkansas has increased our access to markets for our natural gas production, these markets are also served by a number of other suppliers. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. Outside Arkansas, we face competition from a large number of other producers. We also face competition for pipeline and other services to transport our product in to market, particularly in the Northeastern United States.

We cannot predict whether and to what extent any market reforms initiated by the Federal Energy Regulatory Commission, or the FERC, or any new energy legislation will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas production is sold. However, we do not believe that we will be disproportionately or regulatory affected as compared to other natural gas and oil producers and marketers by any action taken by the FERC or any other legislative body.

Regulation

The exploration and development of natural gas and oil resources and the transportation and sale of production historically have been heavily regulated. For example, state governments regulate the location of wells and establish the minimum size for spacing units. Permits typically are required before drilling. State and local government zoning and land use regulations may also limit the locations for drilling and production. Similar regulations can also affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services may require licensing.

Currently in the United States, the price at which natural gas or oil may be sold is not regulated. Congress has imposed price regulation from time to time, and there can be no assurance that the current, less stringent regulatory approach will continue. The federal government prohibits the export of crude oil with limited exceptions and requires permits to export natural gas. Broader freedom to export could lead to higher prices. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act and the rules that the Commodities Futures Trading Commission, or the CFTC, and the SEC have issued under it regulate certain futures and options contracts in the major energy markets, including for natural gas and oil. These regulations require us to comply with margin requirements and with certain clearing and trade execution requirements in connection with our derivative activities.

The exploration and development of natural gas and oil is also subject to extensive environmental regulation. We refer you to Other Environmental Regulation in Item 1 of Part 1 of this Annual Report and the risk factor We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Midstream Services

We believe our Midstream Services segment is well-positioned to complement our E&P initiatives and to compete with other midstream providers for unaffiliated business. We generate revenue from gathering fees associated with the transportation of natural gas to market and through the marketing of natural gas. Our gathering assets support our E&P

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operations and are currently concentrated in the Fayetteville Shale in Arkansas and Northeast Appalachia in Pennsylvania. We plan to divest our Northeast Appalachia gathering assets in 2015.

Our operating income from this segment was $361 million on revenues of $4.4 billion in 2014, compared to $325 million on revenues of $3.3 billion in 2013 and $294 million on revenues of $2.4 billion in 2012. Revenues increased in 2014 and 2013 primarily due to an increase in the prices received for volumes marketed and an increase in volumes marketed. Adjusted EBITDA generated by our Midstream Services segment was $418 million in 2014, compared to $377 million in 2013 and $339 million in 2012. The increases in 2014 and 2013 operating income and Adjusted EBITDA were primarily due to increased gathering revenues, partially offset by increased operating costs and expenses. Adjusted EBITDA is a non-GAAP measure. We refer you to Management s Discussion and Analysis in Item 1 of Part I of this Annual Report for a table that reconciles Adjusted EBITDA to net income (loss).

Gas Gathering

We engage in gas gathering activities primarily in Arkansas related to the development of our Fayetteville Shale asset and in Pennsylvania related to the development of our Northeast Appalachia asset. In 2014, we invested approximately $144 million related to these activities and had gathering revenues of $562 million, compared to $158 million invested and revenues of $516 million in 2013 and $165 million invested and revenues of $474 million in 2012.

We continue to expand our network of gathering lines and facilities throughout the Fayetteville Shale area. During 2014, we gathered approximately 812 Bcf of natural gas in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party operated wells. During 2013, we gathered approximately 790 Bcf of natural gas volumes in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party operated wells. In 2012, we gathered approximately 781 Bcf of natural gas volumes in the Fayetteville Shale area, including 56 Bcf of natural gas from third-party wells. At the end of 2014, we had approximately 2,017 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 590,975 horsepower had been installed at 63 central point gathering facilities in the Fayetteville Shale.

We also engage in gathering activities in Pennsylvania, Louisiana and East Texas. During 2014, we gathered approximately 151 Bcf of natural gas volumes in Northeast Appalachia, Louisiana and East Texas. During 2013, we gathered approximately 110 Bcf of natural gas in Northeast Appalachia and East Texas. In 2012, we gathered approximately 65 Bcf of natural gas in Northeast Appalachia and East Texas. The increase in volumes gathered over the past three years was primarily due to our growing production volumes in Northeast Appalachia. At year-end 2014, we had approximately 105 miles of pipe in Pennsylvania, 25 miles of pipe in Texas and 16 miles of pipe in Louisiana. As of December 31, 2014, compression equipment representing in aggregate approximately 53,035 horsepower had also been installed at 4 central point gathering facilities in Pennsylvania. We plan to divest of our Northeast Appalachia gathering assets in 2015.

Gas Marketing

We attempt to capture downstream opportunities related to marketing and transportation of natural gas. Our current marketing strategy primarily involves the marketing of our own natural gas production. Additionally, we manage portfolio and basis risk, acquire transportation rights on third-party pipelines and in limited circumstances, purchase third-party natural gas. During 2014, we marketed 904 Bcf of natural gas, compared to 800 Bcf in 2013 and 676 Bcf in 2012. Of the total volumes marketed, production from our affiliated E&P operations accounted for 97% in 2014, compared to 96% in 2013 and 95% in 2012.

Fayetteville Shale Marketing

We are a foundation shipper on two pipeline projects serving the Fayetteville Shale. The Fayetteville Express Pipeline LLC, or FEP, is a 2.0 Bcf per day pipeline that is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. FEP was placed in service in January 2011. We have a maximum aggregate commitment of approximately 1,200,000 Dekatherms per day for an initial term of ten years from the in-service date. Texas Gas Transmission, LLC or Texas Gas, a subsidiary of Boardwalk Pipeline Partners, LP, constructed two pipeline laterals called the Fayetteville and Greenville Laterals, which also provide transportation for our Fayetteville Shale gas. We have maximum aggregate commitments of approximately 800,000 Mcf per day on the Fayetteville Lateral and 640,000 Mcf per day on the Greenville Lateral.

The Fayetteville and the Greenville Laterals and the FEP allow us to transport our natural gas to interconnecting pipelines that offer connectivity and marketing options to the eastern half of the United States. These interconnecting pipelines include Centerpoint, Natural Gas Pipeline, Mississippi River Transmission, Gulf South, Texas Gas, Tennessee

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Gas Pipeline, Trunkline, ANR, Columbia Gulf, Texas Eastern, and Sonat. We rely in part upon the Fayetteville and Greenville Laterals and the FEP to service our production from the Fayetteville Shale.

Northeast Appalachia

During 2011 and 2012, we entered into a number of short- and long-term firm transportation service agreements in support of our growing Northeast Appalachia operations in Pennsylvania. In March 2011, we entered into a precedent agreement with Millennium Pipeline Company, L.L.C. pursuant to which we entered into short- and long-term firm natural gas transportation services on Millennium s existing system. Expansions of the system were placed in-service in the second quarter of 2013 and the second quarter of 2014.

We have also executed firm transportation agreements with Tennessee Gas Pipeline Company (TGP), a subsidiary of Kinder Morgan Energy Partners, L.P., that increase our ability to move our Northeast Appalachia natural gas production in the short term to market as well as a precedent agreement for an expansion project that was placed in-service in November 2013 pursuant to which SES has subscribed for approximately 100,000 Dekatherms per day of capacity. TGP s expansion project will expand its 300 Line in Pennsylvania to provide natural gas transportation from the northeast Appalachia supply area to existing delivery points on the TGP system.

In March 2012, we entered into a precedent agreement with Constitution Pipeline Co. LLC for a proposed 121-mile pipeline connecting to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, New York. Subject to the receipt of regulatory approvals and satisfaction of other conditions, we agreed to enter a 15-year firm transportation agreement with a total capacity of approximately 150,000 Mcf per day on this project. Constitution Pipeline Co. LLC has extended the range for the pipeline s target in-service date to late 2015 through 2016 as a result of a longer than expected regulatory and permitting process. We have provided certain guarantees of a portion of our obligations under these agreements.

In May 2013, we entered into a precedent agreement with Columbia Gas Transmission, LLC for a project that will expand their existing system from Chester County, Pennsylvania to various interconnects throughout Pennsylvania, New Jersey, Maryland, and Virginia. Our volume on this project is 72,000 Mcf per day and it is expected to be in service by the third quarter of 2015.

In January 2014, we entered into a precedent agreement with Transcontinental Gas Pipeline Company LLC that will provide additional firm transportation capacity for supplies of natural gas from northern Pennsylvania to markets along the Transco pipeline system stretching from the northeastern US in Transco s Zone 6, to Zone 5 and terminating in Zone 4. Subject to the receipt of regulatory approvals and satisfaction of other conditions, we agreed to enter a 15-year firm transportation agreement with a total capacity of approximately 44,000 Mcf per day on this project and is expected to be in service in the second half of 2017.

In January 2015, we completed the purchase of certain oil and gas assets in northeast Pennsylvania and assumed short and long-term natural gas transportation agreements with Millennium Pipeline Company, L.L.C. with a total capacity of approximately 260,000 Mcf per day.

Southwest Appalachia

As part of our December 2014 acquisition of oil and gas assets in West Virginia and southwest Pennsylvania, we were assigned approximately 92,000 Mcf per day of capacity on the Columbia Gas Transmission pipeline. Additionally, we were assigned a precedent agreement with ET Rover Pipeline LLC for approximately 200,000 Mcf per day of capacity. ET Rover Pipeline LLC is constructing a new interstate pipeline to receive and transport natural gas from Marcellus and Utica production outlets to points of interconnection with Panhandle Eastern Pipe Line Company and

ANR Pipeline, to interconnections in Michigan, to the Union Gas Dawn Hub and to certain off-system delivery points on Trunkline Zone 1A, and is anticipated to be in service by the second quarter 2017.

In addition to the December 2014 assignment of natural gas transportation agreements, we were assigned certain ethane transportation agreements that allow for the transport of our ethane production to both domestic and international markets.

Demand Charges

As of December 31, 2014, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $5.4 billion and the Company has guarantee obligations of up to $173 million of that amount.

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We refer you to the risk factor If our Fayetteville Shale and Northeast Appalachia drilling programs fail to produce our projected supply of natural gas, the value of our investments in our gathering operations could be diminished. In addition, our commitments for transportation on third-party pipelines and gathering systems could make the sale of our natural gas uneconomic, which could have an adverse effect on our results of operations financial condition and cash flows.

Competition

Our gas gathering and marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are other producers and affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. Other factors affecting competition are the cost and availability of alternative fuels, the level of consumer demand and the cost of and proximity to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

Regulation

The transportation and sale of natural gas and oil are heavily regulated. Interstate pipelines must obtain authorization from the FERC, to operate in interstate commerce, and state governments typically must authorize the construction of pipelines for intrastate service. The FERC currently allows interstate pipelines to adopt market-based rates; however, in the past the FERC has regulated pipeline tariffs and could do so again in the future. State tariff regulations vary. Currently, all our pipelines are intrastate.

State and local permitting, zoning and land use regulations can affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services to our midstream business may require licensing.

The transportation of natural gas and oil is also subject to extensive environmental regulation. We refer you to Other Environmental Regulation in Item 1 of Part I of this Annual Report and the risk factor We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Other

Our other operations have primarily consisted of real estate development activities. In 2013, we started construction on a corporate office complex located in Spring, Texas on 26 acres of commercial land that we purchased in 2012. The Company financed the construction of this complex through a construction agreement and lease arrangement. As of December 31, 2014, we were obligated for the construction costs incurred, which approximated $137 million. In January 2015, construction on the corporate office was completed and the Company commenced a lease with a term of approximately five years.

During 2012, we sold our office complex in Fayetteville, Arkansas and our interest in approximately 9.5 acres of real estate near the Fayetteville complex. In 2012, we also sold our office complex in Conway, Arkansas for approximately $32 million and subsequently leased back our Conway complex from the buyer for a 15-year term. There were no sales of commercial real estate in 2014 or 2013.

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Environmental Regulation

General. Our operations are subject to environmental regulation in the jurisdictions in which we operate. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements to drill or operate wells and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the natural gas and oil industry in general. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

The following is a summary of the more significant existing environmental and worker health and safety laws and regulations to which we are subject.

Certain U.S. Statutes. CERCLA, also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended, or RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil, natural gas or geothermal energy. However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as hazardous wastes, which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Clean Water Act, as amended, or CWA, and analogous state laws, impose restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to regulated waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

The Oil Pollution Act, as amended, or the OPA, and regulations thereunder impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. Although liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

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In 2014, 2013 and 2012, oil accounted for less than 1% of our total production, although we expect this percentage to increase as we develop our Southwest Appalachia assets.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed on them may be subject to CERCLA, the Clean Water Act, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

The Clean Air Act, as amended, restricts emissions into the atmosphere. Various activities in our operations, such as drilling, pumping and the use of vehicles, can release matter subject to regulation. We must obtain permits, typically from local authorities, to conduct various activities. Federal and state governmental agencies are looking into the issues associated with methane and other emissions from oil and natural gas activities, and further regulation could increase our costs or restrict our ability to produce. Although methane emissions are not currently regulated at the federal level, we are required to report emissions of various greenhouse gases, including methane.

Hydraulic Fracturing. We utilize hydraulic fracturing in drilling wells as a means of maximizing their productivity. It is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense and deep rock formations. The knowledge and expertise in fracturing techniques we have developed through our operations in the Fayetteville Shale and Northeast Appalachia are being utilized in our other operating areas, including Southwest Appalachia, the Sand Wash Basin and our Lower Smackover Brown Dense acreage and, in the future, may include our exploration program in New Brunswick, Canada. Successful hydraulic fracturing techniques are also expected to be critical to the development of other New Venture areas. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. In the Fayetteville Shale and Northeast Appalachia, the fracturing fluids we use are comprised of approximately 99.9% water and sand on a percentage volume basis. The remaining 0.1% is comprised of small quantities of additives which contain chemical compounds such as hydrochloric acid, phosphoric acid, glutaraldehyde and sodium chloride.

In the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing practice, both in the United States and abroad. In the United States, hydraulic fracturing is typically regulated by state oil and natural gas commissions, but there have recently been a number of regulatory initiatives at the federal and local levels as well as by other state agencies. New York State currently has a moratorium on hydraulic fracturing, and some local governments in the United States also ban this procedure. We currently do not have material properties in these areas. The newly elected provincial government in New Brunswick recently announced an intent to impose a moratorium on hydraulic fracturing until a list of conditions is met and has introduced authorizing legislation in the provincial legislature. We have applied for an extension of our licenses past the end of the moratorium, but as of this time that extension has not been granted. The list of conditions that the provincial government has announced is subjective, and we cannot predict the duration of the moratorium or whether we will be granted the extension requested or any other extension. Unless and until the moratorium is lifted and our licenses are extended, we will not be able to continue with our program in New Brunswick.

For example, the Environmental Protection Agency, or EPA, issued final rules effective as of October 15, 2012 that subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the

New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS programs. The EPA final rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion, or REC techniques developed in the EPA's Natural Gas STAR program. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the final regulations under NESHAPS include maximum achievable control technology, or MACT, standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Based on our current operations and practices, management believes, such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management s view may change in the future.

In October 2011, the EPA also announced a schedule for development of standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works or POTWs. The regulations will be developed

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under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. The EPA anticipates issuing the proposed rules in 2015.

In addition to the EPA, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A final draft of the report is expected for peer review and public comment in 2015. The U.S. Department of the Interior also is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Some states in which we operate have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We refer you to the risk factor Our financial condition and results of operation could be adversely affected by legislative and regulatory initiatives in the United States and elsewhere relating to environmental matters, particularly hydraulic fracturing and climate change, which could result in increased costs and additional operating restrictions or delays or prevent us from realizing the value of undeveloped acreage in Item 1A of Part I of this Annual Report.

Employee health and safety. Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (OSHA) and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Canada. Our activities in Canada have, to date, been limited to certain geological and geophysical activities that are not subject to extensive environmental regulation. If and when we begin drilling and development activities in New Brunswick, we will be subject to federal, provincial and local environmental regulations that we believe require compliance efforts comparable to those required in the United States.

Employees

As of December 31, 2014, we had 2,781 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2014. We believe that our relationships with our employees are good. In 2014, we were named a Top Workplace by the Houston Chronicle for the fifth consecutive year.

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GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below apply to the indicated terms as used in this Annual Report. All natural gas reserves and production reported in this Annual Report are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit. All currency amounts are in U.S. dollars unless specified otherwise.

Acquisition of properties Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers fees, recording fees, legal costs, and other costs incurred in acquiring properties. For additional information, see the SEC s definition in Rule 4-10(a) (1) of Regulation S-X, a link for which is available at the SEC s website.

Adjusted EBITDA Net income (loss) plus interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties or (gain) loss on derivatives, net of settlement. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Reconciliation of Non-GAAP Measures in Item 7 of Part II of this Annual Report for a table that reconciles Adjusted EBITDA with our net income (loss) from our audited financial statements.

Analogous reservoir Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

For additional information, see the SEC s definition in Rule 4-10(a) (2) of Regulation S-X, a link for which is available at the SEC s website.

Available reserves Estimates of the amounts of oil and natural gas which the registrant can produce from current proved developed reserves using presently installed equipment under existing economic and operating conditions and an estimate of amounts that others can deliver to the registrant under long-term contracts or agreements on a per-day, per-month, or per-year basis. For additional information, see the SEC s definition in Item 1207(d) of Regulation S-K, a link for which is available at the SEC's website.

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf One billion cubic feet of natural gas.

Bcfe One billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of oil to six Mcf of natural gas.

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

Dekatherm One million British thermal units (Btus).

Deterministic estimate The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure. For additional information, see the SEC s definition in Rule 4-10(a) (5) of Regulation S-X, a link for which is available at the SEC s website.

Developed oil and gas reserves Developed oil and natural gas reserves are reserves of any category 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.

For additional information, see the SEC s definition in Rule 4-10(a) (6) of Regulation S-X, a link for which is available at the SEC s website.

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Development costs Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

For additional information, see the SEC s definition in Rule 4-10(a) (7) of Regulation S-X, a link for which is available at the SEC s website.

Development project A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project. For additional information, see the SEC s definition in Rule 4-10(a) (8) of Regulation S-X, a link for which is available at the SEC s website.

Development well A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. For additional information, see the SEC s definition in Rule 4-10(a) (9) of Regulation S-X, a link for which is available at the SEC s website.

Downspacing The process of drilling additional wells within a defined producing area to increase recovery of natural gas and oil from a known reservoir.

E&P Exploration for and production of natural gas and oil.

Economically producible The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities. For additional information, see the SEC s definition in Rule 4-10(a) (10) of Regulation S-X, a link for which is available at the SEC s website.

Estimated ultimate recovery (EUR) Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date. For additional information, see the SEC s definition in Rule 4-10(a) (11) of Regulation S-X, a link for which is available at the SEC s website.

Exploitation The development of a reservoir to extract its gas and/or oil.

Exploratory well 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. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section. For additional information, see the SEC s definition in Rule 4-10(a) (13) of Regulation S-X, a link for which is available at the SEC s website.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc. For additional information, see the SEC s definition in Rule 4-10(a) (15) of Regulation S-X, a link for which is available at the SEC s website.

Fracture stimulation A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

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Gross well or acre A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. For additional information, see the SEC's definition in Item 1208(c)(1) of Regulation S-K, a link for which is available at the SEC's website.

Gross working interest Gross working interest is the working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest.

Infill drilling Drilling wells in between established producing wells to increase recovery of natural gas and oil from a known reservoir.

MBbls One thousand barrels of oil or other liquid hydrocarbons.

Mcf One thousand cubic feet of natural gas.

Mcfe One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

MMBbls One million barrels of oil or other liquid hydrocarbons.

MMBtu One million British thermal units (Btus).

MMcf One million cubic feet of natural gas.

MMcfe One million cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

Net revenue interest Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

Net well or Net acre The number of net wells or acres is the sum of the fractional working interests owned in individual wells or tracts. For additional information, see the SEC's definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC's website.

NGL Natural gas liquids.

NYMEX The New York Mercantile Exchange.

Operating interest An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

Overriding royalty interest A fractional, undivided interest or right to production or revenues, free of costs, of a lessee with respect to an oil or natural gas well, that overrides a working interest.

Play A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

Present Value Index or PVI A measure that is computed for projects by dividing the dollars invested into the PV-10 resulting or expecting to result from the investment by the dollars invested.

Probabilistic estimate The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence. For additional information, see the SEC s definition in Rule 4-10(a) (19) of Regulation S-X, a link for which is available at the SEC s website.

Producing property A natural gas and oil property with existing production.

Productive wells Producing wells and wells mechanically capable of production. For additional information, see the SEC's definition in Item 1208(c)(3) of Regulation S-K, a link for which is available at the SEC s website.

Proppant Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

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Proved developed producing Proved developed reserves that can be expected to be recovered from a reservoir that is currently producing through existing wells.

Proved developed reserves Proved gas and oil that are also developed gas and oil reserves.

Proved oil and gas reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Also referred to as proved reserves. For additional information, see the SEC s definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC s website.

Proved reserves See proved oil and gas reserves.

Proved undeveloped reserves Proved oil and gas reserves that are also undeveloped oil and gas reserves.

PV-10 When used with respect to natural gas and oil reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as present value. After-tax PV-10 is also referred to as standardized measure and is net of future income tax expense.

Reserve life index The quotient resulting from dividing total reserves by annual production and typically expressed in years.

Reserve replacement ratio The sum of the estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions (which may include or exclude reserve revisions of previous estimates) for a specified period of time divided by production for that same period of time.

Reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs. For additional information, see the SEC s definition in Rule 4-10(a) (27) of Regulation S-X, a link for which is available at the SEC s website.

Royalty interest An interest in a natural gas and oil property entitling the owner to a share of oil or natural gas production free of production costs.

Tcf One trillion cubic feet of natural gas.

Tcfe One trillion cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

Unconventional play A play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds, or (3) shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

Undeveloped acreage Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. For additional information, see the SEC's definition in Item 1208(c)(4) of Regulation S-K, a link for which is available at the SEC's website.

Undeveloped oil and natural gas reserves Undeveloped oil and natural gas reserves are reserves of any category 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. Also referred to as undeveloped reserves. For additional information, see the SEC s definition in Rule 4-10(a) (31) of Regulation S-X, a link for which is available at the SEC s website.

Undeveloped reserves See undeveloped oil and natural gas reserves.

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USD United States Dollar.

Well spacing The regulation of the number and location of wells over an oil or natural gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission in the applicable jurisdiction. The order may be statewide in its application (subject to change for local conditions) or it may be entered for each field after its discovery. In the operational context, well spacing refers to the area attributable between producing wells within the scope of what is permitted under a regulatory order.

Working interest An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

Workovers Operations on a producing well to restore or increase production.

WTI West Texas Intermediate, the benchmark oil price in the United States.

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ITEM 1A. RISK FACTORS

In addition to the other information included in this Annual Report, the following risk factors should be considered in evaluating our business and future prospects. The risk factors described below represent what we believe are the most significant risk factors with respect to us and our business. In assessing the risks relating to our business, investors should also read the other information included in this Annual Report, including our financial statements and the related notes and Management s Discussion and Analysis of Financial Condition and Results of Operation Cautionary Statement about Forward-Looking Statements.

Our revenues and the value of our assets are highly dependent on the prices for natural gas and, to a lesser extent, oil. These prices are volatile, and a substantial or extended decline in natural gas and oil prices would have a material adverse effect on us.

Our financial results and the value of our assets correlate closely to the prices we can and do obtain for what we produce, in particular natural gas, which historically has accounted for almost 100% of our production. Prices for natural gas and oil are highly volatile and unpredictable. The following factors, among others, affect the supply of and demand for natural gas and oil:

- Changes in consumption patterns, including those resulting from population changes and migrations, new technologies and grown in emerging markets
- Global and local economic conditions
- Inventory levels
- Ability and cost of transporting product to markets, including the ability to connect resources to pipelines or other means of transportation, bottlenecks in pipeline or other transportation capacity such as many are experiencing in the Marcellus and the Utica Shales, export and import controls and other constraints
- Production disruptions
- Actions of governments and multinational groups, such as the Organization of Petroleum Exporting Countries (OPEC)
- Currency exchange rates
- Competition from other producers and from other energy sources, including renewables, which affects the level of supply
- Technological developments
- Weather, earthquakes and other natural events
- Market perceptions of future prices, whether due to the foregoing factors or others

A significant or extended decline in natural gas and oil prices, such as the one from 2008 into 2012 when the NYMEX natural gas price dropped from $13.58 to $1.91 per MMBtu, would have a material adverse effect on our financial position, our results of operations, our access to capital and the quantities of natural gas and oil that we can produce economically, including the following:

- The cash flows from our operations would be reduced, decreasing funds available for capital investments employed to replace reserves or increase production.
- Lower prices would reduce the value of our natural gas and oil assets and, in some cases, make them no longer be economic to produce. This could result in impairments to the values of our assets, such as occurred in 2012.
- Access to other sources of capital, such as equity or debt markets, could be severely limited or unavailable.
- We could fail to meet financial or other covenants in the documentation governing our debt, leading to mandatory prepayments or defaults.
- Locational price differentials change, making it difficult to predict the best locations to conduct our activities.
- Varying perceptions of future prices can lead to difficulties in agreeing on the value of assets in acquisitions or dispositions.

We endeavor to mitigate against these risks through hedging a significant portion of our production. Hedging also presents risks, including our failure to project the appropriate volumes and price points for hedges and the creditworthiness of our counterparties. For a discussion of our hedging activities, we refer you to Note 5 to the consolidated financial statements included in this Annual Report. Additionally, we mitigate these risks, in part, through our Midstream Services business, which generates cash flow that is largely fee-based and thus not directly impacted by commodity price volatility.

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

The marketability of our natural gas and oil production depends in part on the availability, proximity, and capacity of gathering systems, processing and pipeline and other transportation systems owned or operated by third parties. The lack of available capacity in these systems and facilities can result in shutting in producing wells, delaying or discontinuing the development plans for our properties or receiving lower prices. Although we have some contractual control over the transportation and gathering of our production, material changes in these business relationships could materially affect our operations. Federal and state regulation of natural gas and oil production, processing and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, and transport natural gas. In particular, continued development in the Appalachian Basin by us and others could overtax the capacity of existing gathering and pipeline system, and new or expanded capacity may not be in place in time.

The vast majority of our current operations and production are in the Fayetteville Shale, Northeast Appalachia and Southwest Appalachia, and significant events or circumstances affecting one or more of these areas could have a material and adverse effect on our operations in those areas and thus our overall performance.

Production from the Fayetteville Shale and Northeast Appalachia accounted for 64% and 33%, respectively, of our consolidated production and, when considering both our E&P and Midstream Services business, essentially all of our operating income in 2014. Our current Fayetteville Shale operations are almost entirely in Arkansas, and our current Northeast Appalachia and Southwest Appalachia operations currently are only in Pennsylvania and West Virginia. Significant events or circumstances of the types described elsewhere in these Risk Factors or otherwise that affect one or more of these areas would affect a very large part of our operations simultaneously and, even if they do not affect the industry generally, would affect us disproportionately compared to other companies. Those events and circumstances include changes in local laws and regulations, constraints on transportation, natural events, localized price changes and availability of water, skilled personnel, equipment, services and supplies, among others.

If we fail to find or acquire additional reserves, our reserves and production will decline materially from their current levels.

The rate of production from natural gas and oil properties generally declines as reserves are depleted. Unless we acquire additional properties containing proved reserves, conduct successful exploration and development activities, successfully apply new technologies or identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as reserves are produced. Future natural gas and oil production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

Our business could be adversely affected by competition with other companies.

The natural gas and oil industry is highly competitive, and our business could be adversely affected by companies that are in a better competitive position. As an independent natural gas and oil company, we frequently compete for reserve acquisitions, exploration leases, licenses and concessions, marketing agreements, transportation, equipment and labor against companies with financial and other resources substantially larger than those we possess. Many of our competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating in some of our core areas for a much longer time than we have or have established strategic long-term positions in geographic regions in which we may seek new entry.

Natural gas and oil exploration and production is an inherently risky business with many uncertainties and potential liabilities. The results of our activities may not be what we project, and not all our liabilities and other exposures may be covered by insurance.

By its nature, exploring for and producing natural gas and oil involves substantial capital investment with no assurance of return, or returns at expected levels, and the risk of environmental and other liability. Among other things:

· Although we utilize sophisticated geological and geophysical tools to determine where to drill, these do not predict with certainty the presence of natural gas or oil or the rate at which they can be produced. Some wells will result in no production, production that does not cover costs or production at lower levels than expected.

- During drilling we can face difficulties in landing our wellbore in the desired zones, staying in the desired zones while drilling horizontally, penetrating rock formations, controlling well pressure, stimulating reservoirs through fracturing and cleaning the wellbore following fracturing and running casing the entire length of the wellbore. These circumstances can delay completion, increase costs and possibly lead to the abandonment of the particular location.
- When we acquire properties or businesses through acquisitions, including properties already producing, we may fail to assess correctly the potential of the properties, the costs of integration and development, matters affecting legal title and thus the right to drill and ownership of production, the liabilities that we assume as part of the acquisition and the risks associated with ownership, development and operation.
- Equipment can fail or not be available and pipelines can rupture.
- We can encounter well blowouts, cratering, explosions, pipeline failure, fires, brine or other fluids, drainage of production from neighboring properties and other hazards.
- Earthquakes and hurricanes, storms and other weather events can interfere with drilling activities and operations.
- Although we believe we maintain a robust health, safety and environmental program, incidents can occur, whether due to natural events, the actions of third parties or our own errors or oversights. Spills, injuries or other calamities can result in liability for our Company, damage to our properties and interruption of our operations.

We maintain insurance against many potential losses or liabilities arising from our operations in accordance with customary industry practices and in amounts that we believe to be prudent. Our insurance does not protect us against all operational risks; for example, we generally do not maintain business interruption insurance, and pollution and environmental risks generally are not fully insurable. These risks could give rise to significant costs not covered by insurance that could have a material adverse effect upon our financial results.

Our business strategy depends on executing extensive drilling programs and controlling costs to improve our overall return. Shortages of oilfield equipment, services, supplies, raw materials and qualified personnel could adversely affect our ability to implement our programs or to achieve our desired levels of costs.

We are engaged in large-scale programs to develop our assets, particularly in the Fayetteville Shale, Northeast Appalachia and Southwest Appalachia. We are achieving economies of scale through our sizeable operations in these two areas and, in some cases, vertical integration in certain oilfield services, such as drilling, sand mining and pressure control. We nonetheless compete with other companies for oilfield equipment, services, supplies, raw materials and qualified personnel. In particular, the demand for qualified and experienced field personnel to drill wells and conduct field operations and for geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. These factors also cause significant increases in costs for equipment, services, personnel and raw materials (such as sand, cement, manufactured proppants and other materials utilized in the provision of the oilfield services). Higher natural gas and oil prices generally stimulate increased demand and result in increased costs for professional personnel, drilling rigs, crews and associated supplies, equipment, services and raw materials. In addition, our E&P operations also require local access to large quantities of water supplies and disposal services for produced water in connection with our hydraulic fracture stimulations due to prohibitive transportation costs. We cannot be certain when we will experience shortages or cost increases, which could adversely affect our profit margin, cash flow and operating results or restrict our ability to drill wells and conduct ordinary operations.

Our announced drilling plans can change due to various factors.

As of December 31, 2014, we had drilled and completed 3,742 operated wells relating to our Fayetteville Shale play and 277 operated wells relating to Northeast Appalachia. At year-end 2014, after the exclusion of our acreage in the traditional Fairway and the approximately 158,000 net federal acres we hold in the Ozark Highlands Unit, approximately 85% of our leasehold acreage in the Fayetteville Shale was held by production. Approximately 23%

and 54% of our leasehold acreage in Northeast Appalachia and Southwest Appalachia was held by production at year-end 2014, respectively. Our drilling plans are flexible and are dependent upon a number of factors, including the extent to which we can replicate the results of our most successful wells in addition to the natural gas and oil commodity price environment. The determination as to whether we continue to drill wells in our operating areas may depend on any one or more of the following factors:

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- our ability to determine the most effective and economic fracture stimulation;
- our ability to transport our production to the most favorable markets;
- material changes in natural gas prices (including regional basis differentials);
- changes in the costs to drill, complete or operate wells and our ability to reduce drilling risks;
- the extent of our success in drilling and completing horizontal wells;
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment services
- success or failure of wells drilled in similar formations of which would use the same production facilities;
- receipt of additional seismic or other geologic data or reprocessing of existing data;
- the extent to which we are able to effectively operate our own drilling rigs;
- availability and cost of capital; or
- the impact of federal, state and local government regulation, including any increase in severance taxes.

We continue to gather data about our prospects in our operating areas, and it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all.

Our ability to produce natural gas and oil could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our E&P operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Our financial condition and results of operation could be adversely affected by legislative and regulatory initiatives in the United States and elsewhere relating to environmental matters, particularly hydraulic fracturing and climate change, which could result in increased costs and additional operating restrictions or delays or prevent us from realizing the value of undeveloped acreage.

As described more fully under Other Environmental Regulation in Item 1 of Part I of this Annual Report our operations are subject to extensive environmental regulation. New regulations can increase costs or delay or prevent us from achieving our goals. In particular, we often utilize hydraulic fracturing in our drilling activities, and it forms a critical part of our cost structure and success. As also described there, various governmental and non-governmental groups are advocating restrictions and, in some instances, outright bans on the use of hydraulic fracturing.

Our E&P operations are currently focused on the production of hydrocarbons from unconventional sources, and we expect to continue to focus on such resources in the future. The production of hydrocarbons from these sources has an energy intensity that is a number of times higher than that for production from conventional sources. Therefore, we expect that the greenhouse gas intensity of our production will increase in the long-term. We actively seek to reduce the environmental impact of our operations by pursuing more efficient use of natural resources such as hydrocarbons and water and managing and mitigating the emissions to the air, water and soil, with a focus on the reduction of greenhouse gas emissions. With the efforts of our Health, Safety and Environmental Department, we have been able to plan for and comply with environmental initiatives without materially altering our operating strategy. We anticipate making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment that will increase the cost of equipment, materials and services whose production utilizes hydrocarbons. We may also face increased competition from alternative energy sources that do not rely on hydrocarbons. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters and if we are unable to find solutions to environmental initiatives as they arise, including reducing the greenhouse gas emissions for our existing projects, we may have additional costs as well as compliance and operational risks with respect to our existing operations as well as facing difficulties in pursuing new projects.

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Although our estimated natural gas and oil reserve data is independently audited, our estimates are only estimates and thus may prove to be inaccurate.

As described in more detail under Critical Accounting Policies and Estimates Natural Gas and Oil Properties in Item 7 of Part II of this Annual Report, our reserve data represents the estimates of our reservoir engineers made under the supervision of our management, and our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm. Natural gas and oil reserves cannot be measured exactly, however, and our estimates of natural gas and oil reserves requires extensive judgments of reservoir engineering data and projections of cost that will be incurred in developing and producing reserves, along with pricing. Recovery of undeveloped reserves generally requires significant capital investments and successful drilling operations. Actual reserves, costs and prices may differ dramatically from our estimates.

Our operations can be impacted by events beyond our control, adversely affecting our cash flows and results of operations.

A portion of our production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, earthquakes, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, field labor issues or strikes or voluntarily curtailment in response to market conditions. Further, although we operate most of the wells in which we have interests, some are operated by third parties. Although we endeavor to assure that third parties conduct their activities with rigorous regard for health, safety, environment and cost, we do not control them and therefore cannot be sure they will operate to the same standards that we would. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flows and results of operations. Counterparties to contracts, whether those providing us with goods or services or those owing us payments for production or services, may breach their obligations.

We may have difficulty financing our planned capital investments, which could adversely affect our growth.

We have experienced and expect to continue to experience substantial capital investment and working capital needs to implement our drilling program. Our planned capital investments for 2015 are expected to exceed the net cash generated by our operations under current natural gas prices. We expect to be able to borrow under our revolving credit facility to fund capital investments to the extent they exceed our net cash flow and cash on hand. Our ability to borrow under our revolving credit facility is subject to certain conditions. As of December 31, 2014, we would satisfy those conditions; however, if conditions were not satisfied and we were not otherwise able to borrow funds, we would need to curtail our drilling, development and other activities or be forced to sell some of our assets on a possibly unfavorable basis. Any such curtailment or sale could have a material adverse effect on our results and future operations.

We have made significant investments in pipelines and gathering systems and contracts and in oilfield service businesses, including our drilling rig, pressure pumping equipment and sand mine operations, to lower costs and secure inputs for our operations and transportation for our production. If our exploration and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers.

Through December 31, 2014, we had invested approximately $1,184 million in our gas gathering system built for the Fayetteville Shale and approximately $247 million in our gas gathering system built for our operations in Northeast Appalachia. To the extent necessary to gather our production, we may make further substantial investments in the expansion of our gas gathering systems. We have also entered into multiple firm transportation agreements relating to natural gas volumes produced from the Fayetteville Shale as well as a number of firm transportation and gathering agreements relating to the Marcellus Shale. As of December 31, 2014, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $5.4 billion. Our gas gathering business will largely rely on natural gas sourced from our operations. If our Fayetteville Shale and Northeast Appalachia programs fail to produce significant quantities of natural gas within expected timeframes, our investments in our gas gathering operations could be lost, and we could be forced to pay demand or other charges for transportation on pipelines and gathering systems that we would not be using.

We also have made significant investments to meet certain of our oilfield services needs, including establishing our own drilling rig operation, sand mine and pressure pumping capability. If our level of operations is reduced, we may not be able to recover these investments. Further, entering into these service and supply sectors, including competing with them for qualified personnel and supplies, may have an adverse effect on our relationships with our existing third-party service and resource providers or our ability to secure these services and resources from other providers.

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Our drilling plans are subject to change.

As of December 31, 2014, we had drilled and completed 3,742 operated wells relating to our Fayetteville Shale play and 277 operated wells relating to Northeast Appalachia. At year-end 2014, after the exclusion of our acreage in the traditional Fairway and the approximately 158,000 net federal acres we hold in the Ozark Highlands Unit, approximately 85% of our leasehold acreage in the Fayetteville Shale was held by production. Approximately 23% and 54% of our leasehold acreage in Northeast Appalachia and Southwest Appalachia was held by production at year-end 2014, respectively. Our drilling plans are flexible and are dependent upon a number of factors, including the extent to which we can replicate the results of our most successful wells in addition to the natural gas and oil commodity price environment. The determination as to whether we continue to drill wells in our operating areas may depend on any one or more of the following factors:

- our ability to determine the most effective and economic fracture stimulation;
- our ability to transport our production to the most favorable markets;
- material changes in natural gas prices (including regional basis differentials);
- changes in the costs to drill, complete or operate wells and our ability to reduce drilling risks;
- the extent of our success in drilling and completing horizontal wells;
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment services
- success or failure of wells drilled in similar formations of which would use the same production facilities;
- receipt of additional seismic or other geologic data or reprocessing of existing data;
- the extent to which we are able to effectively operate our own drilling rigs;
- availability and cost of capital; or
- the impact of federal, state and local government regulation, including any increase in severance taxes.

We continue to gather data about our prospects in our operating areas, and it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all.

If we fail to drill all of the wells that are necessary to hold our acreage, the lease terms could expire, which would result in the loss of certain leasehold rights.

Leases on approximately 175,220 (including 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management) net acres of our Fayetteville Shale acreage will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Approximately 133,624 and 131,782 net acres of our Northeast Appalachia and Southwest Appalachia acreage, respectively, will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. As discussed above under Our drilling plans are subject to change, our ability to drill wells depends on a number of factors, including certain factors that are beyond our control. With the exception of the Ozark Highlands Unit, which is leased from the Federal Government, the current rules in Arkansas relating to the Fayetteville Shale provide that each drilling unit would consist of a governmental section of approximately 640 acres and operators are permitted to drill up to 16 wells per drilling unit for each unconventional source of supply. In Pennsylvania, the location of our Northeast Appalachia acreage, there are currently no rules establishing requirements for drilling units. In West Virginia, where the bulk of our Southwest Appalachia acreage is located, there is no procedure to compel holders of neighboring interests to join into units. Current rules in these states may change in ways that could impair our ability to drill or maintain our acreage position. In addition, other E&P operator drilling activity could impair our ability to drill and maintain acreage positions. To the extent that any field rules prevent us from successfully drilling wells in certain areas, we may not be able to drill the wells required to maintain our leasehold rights and our leasehold investments could be lost.

We depend upon our management team and our operations require us to attract and retain experienced technical personnel.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy depends, in part, on our experienced management team, as well as certain key geoscientists, geologists, engineers and other professionals employed by us. The success of our technological initiatives that support our business enterprise is also dependent upon attracting and retaining experienced technical professionals. The loss of key members of our management team or other highly qualified technical professionals could have a material adverse effect on our business, financial condition and operating results.

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Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

The elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies has been proposed in recent years. These changes have included, among other proposals:

- Repeal of the percentage depletion allowance for oil and natural gas properties
- Elimination of current deductions for intangible drilling and development costs
- Elimination of the deduction for certain domestic production activities
- Extension of the amortization period for certain geological and geophysical expenditures

It is unclear whether these or similar changes will be enacted. The passage of these or any similar changes in federal income tax laws to eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development could have an adverse effect on our financial position, results of operations and cash flows.

Cyber attacks or terrorist attacks could affect our assets, cash flows and results of operations.

Cyber attacks on businesses are occurring with greater frequency, and natural gas and oil infrastructure and systems could become targets of terrorists. We rely on electronic systems and networks to control and manage our exploration and production, pipeline and marketing operations and have multiple layers of security to mitigate risks of cyber attack. We also have security in place around our physical operations. If we nonetheless were to experience an attack and our security measures failed, the potential consequences to our businesses and the communities in which they operate could be significant.

Our Canadian exploration and production activities are subject to different risks and uncertainties, different from or in addition to those we face in our U.S. operations.

In addition to the various risks associated with our U.S. operations, we are subject to risks and uncertainties related to our Canadian exploration and production activities, including risks related to increases in taxes and governmental royalties, changes in laws and policies governing operations of foreign-based companies, restrictions on imports and exports, expropriation of property, cancellation of contract rights, environmental protection controls, environmental compliance requirements and laws pertaining to workers health and safety. Consequently, our exploration, development and production activities in Canada could be substantially affected by factors beyond our control. In addition, the rights of aboriginal peoples, called First Nations in Canada, are not clear. Our operations in New Brunswick have been subject to local protests, causing several temporary interruptions to our exploration activities. In addition, the newly elected provincial government in New Brunswick recently announced an intent to impose a moratorium on hydraulic fracturing until a list of conditions is met and has introduced authorizing legislation in the provincial legislature. We have applied for an extension of our licenses past the end of the moratorium, but as of this time that extension has not been granted. The list of conditions that the provincial government has announced is subjective, and we cannot predict the duration of the moratorium or whether we will be granted the extension requested or any other extension. Unless and until the moratorium is lifted and our licenses are extended, we will not be able to continue with our program in New Brunswick.

Because we have no plans to pay dividends on our common stock, investors in our common stock must look solely to stock appreciation for a return on their investment in us.

We do not currently pay cash dividends on our common stock, and we do not anticipate paying cash dividends in the foreseeable future. We currently intend to retain all future earnings and other cash resources, if any, for the operation and development of our business and do not anticipate paying cash dividends on our common stock in the foreseeable future. Payment of any future dividends on our common stock will be at the discretion of our board of directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansions. Any future dividends on our common stock may also be restricted by any loan agreements which we may enter into from time to time and from the future issuances of preferred stock. However, until the depositary shares representing the 1/20th interest in our 6.25% Series B Mandatory Preferred Stock convert to common stock, we will pay quarterly dividends to the holders of such depositary shares.

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Anti-takeover provisions in our organizational documents and under Delaware law may impede or discourage a takeover, which could cause the market price of our common stock to decline.

We are a Delaware corporation, and the anti-takeover provisions of Delaware law impose various impediments to the ability of a third party to acquire control of us, even if a change in control would be beneficial to our existing stockholders, which, under certain circumstances, could reduce the market price of our common stock. In addition, protective provisions in our Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws or the implementation by our board of directors of a stockholder rights plan could prevent a takeover, which could harm our stockholders.

Our current and future levels of indebtedness and the terms of our financing arrangements may adversely affect our results and limit our growth.

At December 31, 2014, we had long-term indebtedness of $2.5 billion, including borrowings of $300 million under our revolving credit facility and $500 million under our Term Loan Facility. Also at December 31, 2014, we had short-term indebtedness of $4.5 billion relating to our bridge facility which was repaid in full in January 2015 in part through the issuance of $2.2 billion of additional long-term senior notes. See Note 16 Subsequent Events within Item 8 of this Annual Report for further details on indebtedness incurred subsequent to December 31, 2014.

The terms of the indentures relating to our outstanding senior notes, our credit facilities, and the master lease agreements relating to our drilling rigs and other equipment, which we collectively refer to as our financing agreements, impose restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, which may include, without limitation, one or more of the following:

- incurring additional debt;
- redeeming stock or redeeming debt;
- making investments;
- creating liens on our assets; and
- selling assets.

Although the indenture governing the notes contains covenants that apply to us, covenants limiting liens and sale and leasebacks covenants contain exceptions and limitations that would allow us, pursuant to the terms of the indenture, to create, grant or incur certain liens or security interests. Moreover, the indenture does not contain any limitations on the ability of us or our subsidiaries to incur debt, pay dividends, make investments, or limit the ability of our subsidiaries to make distributions to us. Such activities may, however, be limited by our other financing agreements in certain circumstances.

Our level of indebtedness and off-balance sheet obligations, and the covenants contained in our financing agreements, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Our ability to comply with the covenants and other restrictions in our financing agreements may be affected by events beyond our control, including prevailing economic and financial conditions.

If we fail to comply with the covenants and other restrictions, it could lead to an event of default and the acceleration of our obligations under the notes or our other financing agreements, and in the case of the lease agreements for drilling rigs, loss of use of our drilling rigs. In particular, a significant or extended decline in natural gas or oil prices would have a material adverse effect on our results of operations, our access to capital and the quantities of natural gas and oil that we can produce economically. For example, the New York Mercantile Exchange, or NYMEX, natural gas prices traded at a high of $5.56 in February 2014 and a low of $3.73 in November 2014 based on last-day-of-month settlement. We may not have sufficient funds to make such payments. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure

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you that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

Actual or anticipated changes or downgrades in our credit ratings, including any announcement that our ratings are under further review for a downgrade, could affect the market value of our senior notes and increase our corporate borrowing costs. Such ratings are limited in scope, and do not address all material risks relating to us, but rather reflect only the view of each rating agency at the time the rating is issued. An explanation of the significance of such rating may be obtained from such rating agency. Although we are currently rated investment grade, there can be no assurance that such credit ratings will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency s judgment, circumstances so warrant.

We may be subject to risks in connection with acquisitions, including the Acquisitions, and the integration of significant acquisitions may be difficult.

We have consummated several acquisitions and we periodically evaluate other potential acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of properties, including the Acquisitions, requires an assessment of several factors, including:

· recoverable reserves;
· future oil and natural gas prices and their appropriate differentials;
· availability and cost of transportation of production to markets;
· availability and cost of drilling equipment and of skilled personnel;
· development and operating costs and potential environments and other liabilities;
· regulatory, permitting and similar matters; and
· our ability to obtain external financing to fund the purchase price.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis, and, as is the case with certain liabilities associated with the assets to be acquired, we are entitled to indemnification for only certain environmental liabilities. In addition, we waived or did not include certain environmental and title indemnification in our acquisitions in Southwest Appalachia in exchange for downward adjustments to the purchase prices.

Significant acquisitions, including the Acquisitions, and other strategic transactions may involve other risks, including:

- diversion of our management s attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate assets;
- the challenge of attracting and retaining personnel associated with acquired operations; and
- the failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.

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ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2014 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed 2014 Proved Reserves by Category and Summary Operating Data in Business Exploration and Production Our Proved Reserves in Item 1 of this Annual Report and incorporated by reference into this Item 2. Our proved reserves are based upon estimates prepared for each of our properties annually by the reservoir engineers assigned to the asset management team in the geographic locations in which the property is located. These estimates are reviewed by senior engineers who are not part of the asset management teams and by our Reservoir Supervisor - Reserves, who is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Reservoir Supervisor Reserves has more than 28 years of experience in petroleum engineering, including the estimation of oil and natural gas reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2009, our Reservoir Supervisor - Reserves served in various reservoir engineering roles for Citation Oil & Gas Corporation, Mitchell Energy and Development Corporation, Whites Stone Energy and H.J. Gruy & Associates and is a member of the Society of Petroleum Engineers and Society of Petroleum Evaluation Engineers and is a Licensed Professional Engineer in the state of Texas. He reports to our Vice President and General Manager Strategy, Performance and Innovation who has more than 28 years of experience in reservoir engineering including the estimation of oil and natural gas reserves in multiple basins in the United States. Prior to joining Southwestern in 1993, our Vice President and General Manager Strategy, Performance and Innovation served in various engineering roles for Conoco Inc. and is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers, American Institute of Professional Geologists, IPAA and TIPRO. He is also a Licensed Professional Engineer in the state of Texas. On our behalf, the Vice President and General Manager Strategy, Performance and Innovation engages NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the two technical persons primarily responsible for auditing our proved reserves estimates (1) have over 32 years and over 12 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 22 years and over 12 years of experience in the estimation and evaluation of reserves, respectively; (3) each has a college degree; (4) each is a Licensed Professional Geoscientist in the State of Texas or a Licensed Professional Engineer in the State of Texas; (5) each meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; and (6) each is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. The financial data included in the reserve estimates is also separately reviewed by our accounting staff. Our proved reserves estimates, as internally reviewed and audited by NSAI, are submitted for review and approval to our Chief Executive Officer. Finally, upon his approval, NSAI reports the results of its reserve audit to the Board of Directors with whom final authority over the estimates of our proved reserves rests. A copy of NSAI's report has been filed as Exhibit 99.1 to this Annual Report.

The information regarding our proved undeveloped reserves required by Item 1203 of Regulation S-K is included under the heading Proved Undeveloped Reserves in Business Exploration and Production Our Proved Reserves in Item 1 of this Annual Report.

The information regarding delivery commitments required by Item 1207 of Regulation S-K is included under the heading Sales, Delivery Commitments and Customers in the Business Exploration and Production Our Operations in

Item 1 of this Annual Report and incorporated by reference into this Item 2. For additional information about our natural gas and oil operations, we refer you to Note 4 to the consolidated financial statements. For information concerning capital investments, we refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Investments. We also refer you to Item 6, Selected Financial Data in Part II of this Annual Report for information concerning natural gas and oil produced.

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The information regarding oil and gas properties, wells, operations and acreage required by Item 1208 of Regulation S-K is set forth below. Figures as of December 31, 2014 exclude assets acquired in 2015, such as those in the Appalachian Basin.

Leasehold acreage as of December 31, 2014:

		Undeveloped		Developed	
		Gross	Net	Gross	Net
Fayetteville Shale (1)		454,857	267,456	828,052	496,831
Appalachia:					
Northeast (2)		233,262	205,491	62,504	60,582
Southwest (3)		347,875	188,244	341,508	225,132
Ark-La-Tex:					
Conventional Arkoma (4)		47,687	45,425	203,738	183,364
East Texas (5)		259	64	64,748	48,228
New Ventures:					
USA New Ventures	Brown Dense (6)	390,917	299,878	4,903	4,493
USA New Ventures	Sand Wash Basin (7)	532,391	370,633	9,173	5,864
USA New Ventures	Other (8)	1,120,139	783,418		
Canada New Ventures (9)		2,716,758	2,716,758		
		5,844,145	4,877,367	1,514,626	1,024,494

(1) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 15,289 net acres in 2015, 921 net acres in 2016 and 779 net acres in 2017 (excluding 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management).

(2) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 35,215 net acres in 2015, 28,912 net acres in 2016 and 69,497 net acres in 2017.

(3) Assuming successful wells are not drilled to develop the acreage and leases are not extended leasehold expiring over the next three years will be 46,342 net acres in 2015, 41,184 net acres in 2016 and 44,256 net acres in 2017. Of this acreage, 16,876 net acres in 2015, 17,798 net acres in 2016 and 15,691 net acres in 2017 can be extended for an average of an additional 4.6 years.

(4) Includes 123,442 net developed acres and 432 net undeveloped acres in the Arkoma Basin that are also within our Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above. Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 15,332 net acres in 2015, 5,533 net acres in 2016 and 986 net acres in 2017.

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 64 net acres in 2015, zero net acres in 2016 and zero net acres in 2017.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 153,866 net acres in 2015, 60,078 net acres in 2016 and 17,057 net acres in 2017.

(7) Assuming successful wells are not drilled to develop the acreage and our exploration license agreements are not extended, leasehold expiring over the next three years will be 107,963 net acres in 2015, 85,977 net acres in 2016, and 34,970 net acres in 2017.

(8) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 143,109 net acres in 2015, 253,728 net acres in 2016 and 72,709 net acres in 2017.

(9) Assuming successful wells are not drilled to develop the acreage and our exploration license agreements are not extended, leasehold expiring over the next years will be 2,518,518 net acres in 2015, 48,960 net acres in 2016, and 148,480 net acres in 2017.

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Producing wells as of December 31, 2014:

	Natural Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Fayetteville Shale	4,027	2,777			4,027	2,777	3,517
Appalachia:							
Northeast (1)	522	257			522	257	256
Southwest	1,034	800			1,034	800	922
Ark-La-Tex:							
Conventional Arkoma(2)	1,138	556			1,138	556	542
East Texas(3)	146	90	7	4	153	94	119
New Ventures	9	6	4	4	13	10	13
	6,876	4,486	11	8	6,887	4,494	5,369

(1) Includes 226 gross natural gas wells in which we own an overriding royalty interest.
(2) Includes 140 gross natural gas wells in which we own an overriding royalty interest.
(3) Includes 1 gross oil well and 11 gross natural gas wells in which we own an overriding royalty interest.

The information regarding drilling and other exploratory and development activities required by Item 1205 of Regulation S-K is set forth below:

	Exploratory(1)					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2014	8.0	8.0			8.0	8.0
2013	3.0	2.5	1.0	1.0	4.0	3.5
2012	7.0	7.0			7.0	7.0

	Development(1)					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2014	272.0	213.0			272.0	213.0
2013(2)	337.0	253.1	3.0	1.5	340.0	254.6
2012(3)	376.0	257.0	9.0	6.7	385.0	263.7

(1) We have not drilled any exploratory or development wells in Canada in the past three years.
(2) 2013 dry wells include 2 gross wells in the Fayetteville Shale that were plugged and abandoned after being spud due to changes in the development plans.
(3) 2012 dry wells include 5 gross wells that were used for science in the Ozark Highlands Unit that were not intended to produce.

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The following table presents the information regarding our present activities required by Item 1206 of Regulation S-K:

Wells in progress as of December 31, 2014: (1,2)

	Gross	Net
Drilling:		
Exploratory		
Development	182.0	153.4
Total	182.0	153.4
Completing:		
Exploratory	3.0	3.0
Development	153.0	117.1
Total	156.0	120.1
Drilling & Completing:		
Exploratory	3.0	3.0
Development	335.0	270.5
Total	338.0	273.5

(1) As of December 31, 2014, we did not have any drilling activities in Canada.

(2) Includes 42 wells in progress acquired in the Chesapeake Property Acquisition.

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The information regarding oil and gas production, production prices and production costs required by Item 1204 of Regulation S-K is set forth below:

Production, Average Sales Price and Average Production Cost:

	For the years ended December 31,		
	2014	2013	2012
Production (Bcfe):			
Fayetteville Shale	494	486	486
Northeast Appalachia	254	151	54
Southwest Appalachia	3		
Other	17	20	25
Total	768	657	565
Average natural gas price per Mcf, excluding hedges:			
Fayetteville Shale	$3.86	$3.13	$2.30
Northeast Appalachia	3.48	3.25	2.55
Total	$3.74	$3.17	$2.34
Average realized gas price per Mcf, including hedges	$3.72	$3.65	$3.44
Oil production (MBbls)(1)	235	138	83
Average oil price per Bbl(1)	$79.91	$103.32	$101.54
NGL production (MBbls)(1)	231	50	
Average NGL price per Bbl(1)	$15.72	$43.63	$
Average production cost per Mcfe, excluding ad valorem and severance taxes:			
Fayetteville Shale	$0.92	$0.86	$0.83
Northeast Appalachia	0.83	0.80	0.46
Total	$0.91	$0.86	$0.80

(1) Our Fayetteville Shale and Northeast Appalachia operations did not produce any oil for the years ended December 31, 2014, 2013 and 2012.

During 2014, we were required to file Form 23, Annual Survey of Domestic Oil and Gas Reserves, with the U.S. Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 4 to the consolidated financial statements in Item 8 to this Annual Report. The primary differences are that Form 23 reports gross reserves, including the royalty owners share, and includes reserves for only those properties of which we are the operator.

Miles of Pipe

As of December 31, 2014, our Midstream Services segment had 2,017 miles, 105 miles, 25 miles and 16 miles of pipe in its gathering systems located in Arkansas, Pennsylvania, Texas and Louisiana, respectively.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than that we endeavor to conduct prior to drilling, which is consistent with standard practice in the oil and natural gas industry. Generally, before we commence drilling operations on properties that we operate, we conduct a title examination and perform curative work with respect to significant defects that we identify. We believe that we have performed title examination with respect to substantially all of our active properties that we operate.

ITEM 3. LEGAL PROCEEDINGS

We are subject to laws and regulations relating to the protection of the environment. Our policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position, results of operations, and cash flows.

Tovah Energy

In February 2009, one of our subsidiaries was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et al., pending in the 273rd District Court in Shelby County, Texas. By the time of trial in December 2010, Ms. Berry-Helfand (the only remaining plaintiff) alleged that, in 2005, she provided our subsidiary with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that our subsidiary refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, she alleged various statutory and common law claims, including, but not limited to, claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by our subsidiary between February 2005 and February 2006. She also sought disgorgement of our subsidiary s profits. A former associate of the plaintiff intervened in the matter claiming to have helped develop the prospect years earlier.

The jury found in favor of the plaintiff and the intervenor with respect to all of the statutory and common law claims and awarded $11 million in compensatory damages but no special, punitive or other damages. Separately, the jury determined that our subsidiary s profits for purposes of disgorgement, if ordered as a remedy, were $382 million. (Disgorgement of profits is an equitable remedy determined by the judge, and it is within the judge s discretion to award none, some or all of unlawfully obtained profits.) In August 2011, a judgment was entered pursuant to which the plaintiff and the intervenor were entitled to recover approximately $11 million in actual damages and approximately $24 million in disgorgement as well as prejudgment interest and attorneys fees, which currently are estimated to be up to $9 million, and all costs of court of the plaintiff and intervenor.

Both sides appealed and in July 2013, the Tyler Court of Appeals ordered that (1) the judgment awarding the plaintiff and the intervenor $24 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11 million for actual damages, insofar as it is based on the jury s findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret is reversed and judgment rendered that the plaintiff and the intervenor take nothing under those theories of recovery, (3) the award of $11 million to the plaintiff and the intervenor as damages for misappropriation of trade secret is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney s fees for our subsidiary as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. All parties petitioned for rehearing. The Tyler Court of Appeals denied rehearing in November 2013.

Our subsidiary filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor filed cross-petition for review in April 2014, but conditioned their filing on the court s granting our subsidiary s petition for review; i.e., if the court denies our subsidiary s petition for review, then the plaintiff and the intervenor are not seeking further review of the court of appeals judgment. On October 24, 2014, the Supreme Court requested full briefing on the merits of the case. Based on our understanding and judgment of the facts and merits of this case, including appellate matters, and after considering the advice of counsel, we have determined that, although reasonably possible, a materially adverse final outcome to this action is not probable. As such, we have not accrued any amounts with respect to this action. If the Supreme Court declines to rule on the case or affirms all aspects of the court of appeals judgment, then our subsidiary would owe the $11 million in damages, plus interest and attorneys fees, offset by any award of attorneys fees for its prevailing on the theft count. Our assessment may change in the future due to occurrence of certain events, such as the result of the petitions for review at the Supreme Court of Texas, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the our results of operations, financial position or cash flows.

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Arkansas Royalty Litigation

Certain of our subsidiaries are defendants in two cases filed in Arkansas state court in 2010 and 2013, and we and certain subsidiaries are defendants in a case filed in federal court in 2014, in each instance brought on behalf of putative classes of royalty owners on some of our leases located in Arkansas. The chief complaint in all three cases is that one of our subsidiaries underpaid the royalty owners by, among other things, deducting from royalty payments costs for gathering, transportation, and compression of natural gas in excess of what is permitted by the relevant leases. Our subsidiaries removed the two cases filed in state court to federal court, but both were remanded to state court during the third quarter of 2014. In September and October 2014 the judges in the two Arkansas state actions entered orders certifying classes of royalty owners who are citizens of Arkansas. Our subsidiaries are appealing those orders. Discovery regarding the plaintiffs theories of liability and amount of claimed damages is in the very early stages. Management believes that the deductions from royalty payments as calculated are permitted and intends to defend the cases vigorously. Our assessment may change in the future due to the occurrence of certain events, such as adverse judgments, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to our results of operations, financial position or cash flows.

Other

We are subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and all subject to inherent uncertainties; therefore, management s view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated.

ITEM 4. MINE SAFETY DISCLOSURES

Our sand mining operations in support of our E&P business are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Annual Report.

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PART II

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

Our common stock is traded on the New York Stock Exchange (the NYSE) under the symbol SWN. On February 24, 2015, the closing price of our common stock trading under the symbol SWN was $27.74 and we had 3,277 stockholders of record, respectively. The following table presents the high and low sales prices for closing market transactions for our common stock trading under the symbol SWN as reported on the NYSE.

	Range of Market Prices					
Quarter Ended	2014		2013		2012	
March 31	$46.57	$38.01	$38.86	$32.09	$35.60	$29.06
June 30	$48.93	$44.33	$39.58	$34.97	$32.46	$25.82
September 30	$44.99	$34.95	$39.91	$36.38	$35.76	$30.55
December 31	$36.50	$27.24	$40.18	$35.16	$36.60	$32.78

We do not currently pay quarterly cash dividends on our common stock.

Issuer Purchases of Equity Securities

The table below sets forth information with respect to purchases of our common stock made by us or on our behalf during the quarter ended December 31, 2014:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
December 1 - 31, 2014	12,133	$29.99	n/a	n/a
Total fourth-quarter 2014:	12,133	$29.99	n/a	n/a

(1) Reflects shares retired by us to satisfy applicable tax withholding obligations due on employee stock plan share issuances. All changes in common stock in treasury in 2014 were due to purchases and sales of shares held on behalf of participants in a non-qualified deferred compensation supplemental retirement savings plan.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2014, 2013 or 2012.

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STOCK PERFORMANCE GRAPH

The following graph compares, for the last five years, the performance of our common stock to the S&P 500 Index and the Dow Jones U.S. Exploration & Production Index. The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2009, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance. This year we are changing the index we will be using to show our performance relative to peers. In the past we have used the Dow Jones Oil & Gas Exploration & Production Index. As now configured, that index includes refining and fully integrated companies as well as companies that, like ours, are largely focused on exploration and production. Going forward, we will be using the same group of peer companies that we use in determining our annual incentive awards, which are all predominately E&P companies. This graph includes both the Dow Jones Index and the peer group, as well as the S&P 500 Index, which we will continue to use. The peer group includes Cabot Oil & Gas Corp, Cimarex Energy Co, Concho Resources Inc, Continental Resources Inc, Denbury Resources Inc, Devon Energy Corp, EOG Resources Inc, Newfield Exploration Co, Noble Energy Inc, Pioneer Natural Resources Co, Range Resources Corp, Sandridge Energy Inc, SM Energy Co, and Ultra Petroleum Corp.

	12/31/09	12/31/10	12/31/11	12/31/12	12/31/13	12/31/14
Southwestern Energy Company	$ 100	$ 78	$ 66	$ 69	$ 82	$ 57
S&P 500 Index	$ 100	$ 115	$ 117	$ 136	$ 180	$ 205
Peer Group	$ 100	$ 117	$ 114	$ 117	$ 162	$ 137
Dow Jones U.S. Exploration & Production	$ 100	$ 117	$ 112	$ 118	$ 156	$ 139

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2014. This information and the notes thereto are derived from our consolidated financial statements. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations and Financial Statements and Supplementary Data.

	2014	2013	2012	2011	2010
	(in millions except shares, per share, stockholder data and percentages)				
Financial Review					
Operating revenues:					
Exploration and production	$2,862	$2,404	$1,964	$2,099	$1,895
Midstream services	4,358	3,347	2,363	2,860	2,454
Other			3	3	1
Intersegment revenues	(3,182)	(2,380)	(1,600)	(2,010)	(1,735)
	4,038	3,371	2,730	2,952	2,615
Operating costs and expenses:					
Gas purchases midstream services	980	782	592	709	611
Operating and general and administrative expenses	648	519	420	399	337
Depreciation, depletion and amortization	942	787	811	705	590
Impairment of natural gas and oil properties			1,940		
Taxes, other than income taxes	95	79	68	66	51
	2,665	2,167	3,831	1,879	1,589
Operating income (loss)	1,373	1,204	(1,101)	1,073	1,026
Interest expense, net	59	42	35	24	26
Other income (loss), net	(4)	2	1		
Gain (loss) on derivatives	139	26	(15)	2	(5)
Income (loss) before income taxes	1,449	1,190	(1,150)	1,051	995
Provision (benefit) for income taxes:					
Current	21	(11)	19	4	12
Deferred	504	497	(462)	409	379
	525	486	(443)	413	391
Net income (loss)	$924	$704	$(707)	$638	$604
Return on equity	19.8%	19.4%	(23.3%)	16.1%	20.4%
Net cash provided by operating activities	$2,335	$1,909	$1,654	$1,740	$1,643
Net cash used in investing activities	$(7,288)	$(2,216)	$(1,907)	$(2,025)	$(1,726)
Net cash provided by financing activities	$4,983	$277	$291	$284	$86
Common Stock Statistics					
Earnings per share:					
Net income (loss) attributable to Southwestern stockholders Basic	$2.63	$2.01	$(2.03)	$1.84	$1.75

Net income (loss) attributable to Southwestern stockholders Diluted	$2.62	$2.00	$(2.03)	$1.82	$1.73
Book value per average diluted share	$13.23	$10.32	$8.71	$11.34	$8.49
Market price at year-end	$27.29	$39.33	$33.41	$31.94	$37.43
Number of stockholders of record at year-end	3,271	3,259	3,122	3,083	3,043
Average diluted shares outstanding	352,410,683	351,101,452	348,610,503	349,921,413	349,310,666

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	2014	2013	2012	2011	2010
Capitalization (in millions)					
Total debt	$6,967	$1,951	$1,669	$1,343	$1,094
Total equity	4,662	3,622	3,036	3,969	2,965
Total capitalization	$11,629	$5,573	$4,705	$5,312	$4,059
Total assets	$14,925	$8,048	$6,738	$7,903	$6,017
Capitalization ratios:					
Debt	60%	35%	35%	25%	27%
Equity	40%	65%	65%	75%	73%
Capital Investments (in millions) (1)					
Exploration and production	7,254	2,052	1,861	1,978	1,776
Midstream services	144	158	165	161	271
Other	49	25	55	68	73
	$7,447	$2,235	$2,081	$2,207	$2,120
Exploration and Production					
Natural gas:					
Production, Bcf	766	656	565	499	404
Average realized price per Mcf, including hedges	$3.72	$3.65	$3.44	$4.18	$4.62
Average price per Mcf, excluding hedges	$3.74	$3.17	$2.34	$3.56	$3.93
Oil:					
Production, MBbls	235	138	83	97	171
Average price per barrel, including hedges	$79.91	$103.32	$101.54	$94.08	$76.84
Average price per barrel, excluding hedges	$79.91	$103.32	$101.54	$94.08	$76.84
NGL:					
Production, MBbls	231	50			
Average price per barrel, including hedges	$15.72	$43.63	$	$	$
Average price per barrel, excluding hedges	$15.72	$43.63	$	$	$
Total natural gas and oil production, Bcfe	768	657	565	500	405
Lease operating expenses per Mcfe	$0.91	$0.86	$0.80	$0.84	$0.83
General and administrative expenses per Mcfe	$0.24	$0.24	$0.26	$0.27	$0.30
Taxes, other than income taxes per Mcfe	$0.11	$0.10	$0.10	$0.11	$0.11
Proved reserves at year-end:					
Natural gas, Bcf	9,809	6,974	4,017	5,887	4,930
Oil, MMBbls	37.6	0.4	0.2	1	1
NGLs, MMBbls	118.7			-	-
Total reserves, Bcfe	10,747	6,976	4,018	5,893	4,937
Midstream Services					
Gas volumes marketed, Bcf	904	786	676	611	496
Gas volumes gathered, Bcf	963	900	846	746	588

(1) Capital investments include an increase of $155 million for 2014, decreases of $25 million and $37 million for 2013 and 2012, respectively, and increases of $4 million and $14 million for 2011 and 2010, respectively, related to the change in accrued expenditures between years.

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

This Annual Report contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in the Cautionary Statement About Forward-Looking Statements below, in Item 1A - Risk Factors in Part I and elsewhere in this Annual Report. You should read the following discussion with Item 6 - Selected Financial Data and our consolidated financial statements and related notes included in this Annual Report.

OVERVIEW

Background

Southwestern Energy Company is an independent energy company engaged in natural gas and oil exploration, development and production, or E&P. We also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services. We operate principally in two segments: E&P and Midstream Services.

Our primary business is the exploration for and production of natural gas and oil, with our current operations principally focused within the United States on development of two unconventional natural gas reservoirs located in Arkansas and Pennsylvania. Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale, and our operations in northeast Pennsylvania are focused on an unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as Northeast Appalachia). Recently, we acquired a significant stake in properties located in West Virginia and southwest Pennsylvania which we also intend to develop. These operations in West Virginia are also focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as Southwest Appalachia). Collectively, our properties located in West Virginia and Pennsylvania are herein referred to as the Appalachian Basin. To a lesser extent, we have exploration and production activities ongoing in Colorado, Louisiana, Texas and in the Arkoma Basin in Arkansas and Oklahoma. We also actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as New Ventures, and through acquisitions. We also operate drilling rigs in Arkansas and Pennsylvania, as well as in other operating areas, and provide oilfield products and services, principally serving our exploration and production operations.

We are focused on providing long-term growth in the net asset value per share of our business. We derive the vast majority of our operating income and cash flow from the production associated with our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will depend primarily on natural gas and oil prices and our ability to increase our production. We expect our production volumes will continue to increase due to ongoing development in our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia divisions. The price we expect to receive for our production is a critical factor in the capital investments we make in order to develop our properties. In recent years, there has been significant volatility in natural gas prices as evidenced by New York Mercantile Exchange, or NYMEX, natural gas prices ranging from a high of $13.58 per MMBtu in 2008 to a low of $1.91 per MMBtu in 2012. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sale prices for our production. Going forward, we will be impacted by crude oil prices which have ranged from approximately $145 per barrel in July 2008 to approximately $45 per barrel in January 2015. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices.

Recent Financial and Operating Results

In 2014, our net income was $924 million, or $2.62 per diluted share, up from net income of $704 million, or $2.00 per diluted share in 2013. Our net loss was $707 million, or $2.03 per diluted share in 2012. In 2012, we incurred a $1,940 million, or $1,192 million net of taxes, non-cash ceiling test impairment of our United States natural gas and oil properties that resulted from a significant decline in natural gas prices during 2012.

In 2014, our natural gas and oil production increased 17% to 768 Bcfe, up from 657 Bcfe in 2013. The 111 Bcfe increase in our 2014 production resulted from a 103 Bcf increase in net production from our Northeast Appalachia properties and an 8 Bcf increase in net production from our Fayetteville Shale properties. In 2013, our natural gas and oil production increased to 657 Bcfe, up from 565 Bcfe in 2012. We are targeting 2015 natural gas and oil production of 940 to 955 Bcfe, an increase of approximately 23% over our 2014 production, using midpoints. Our year-end reserves

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increased 54% in 2014 to 10,747 Bcfe, up from 6,976 Bcfe at the end of 2013 and 4,018 Bcfe at the end of 2012. The overall increase in total estimated proved reserves in 2014 was primarily due to the acquisition of approximately 413,000 net acres in Southwest Appalachia which increased reserves by 33%, our successful drilling programs in the Fayetteville Shale and Northeast Appalachia and upward performance revisions in Northeast Appalachia where reserves grew 63% from 2013. The overall increase in total estimated proved reserves in 2013 was primarily due to significant additions in our Fayetteville Shale reserves including substantial additions of proved undeveloped reserves primarily driven by an increase in average natural gas prices in 2013 and a 141% growth rate in our reserves in Northeast Appalachia.

Our E&P segment operating income was $1,013 million in 2014, up from an operating income of $879 million in 2013. Operating income in 2014 increased $134 million over 2013 as the revenue impact of our 17%, or 111 Bcfe, increase in production and 2%, or $0.07, increase in our average realized natural gas price more than offset the $324 million increase in operating costs and expenses that resulted from our production growth. Operating income was $879 million in 2013, up from an operating loss of $1,396 million in 2012. The operating loss in 2012 included a $1,940 million non-cash ceiling test impairment of our United States natural gas and oil properties. Excluding the non-cash ceiling test impairment, operating income in 2013 increased $335 million over 2012 as the revenue impact of our 16%, or 92 Bcfe, increase in production and 6%, or $0.21, increase in our average realized natural gas price more than offset the $105 million increase in operating costs that resulted from our production growth.

Operating income for our Midstream Services segment was $361 million in 2014, up from $325 million in 2013 and $294 million in 2012. Operating income for our Midstream Services segment increased in 2014 due to an increase of $46 million in gathering revenues and a $12 million increase in the margin generated from our natural gas marketing activities, which was partially offset by a $22 million increase in operating costs and expenses, exclusive of natural gas purchase costs, that resulted from our continued growth in volumes gathered. Volumes gathered grew to 963 Bcf in 2014 compared to 900 Bcf in 2013. Operating income for our Midstream Services segment increased in 2013 due to an increase of $42 million in gathering revenues and a $17 million increase in the margin generated from our natural gas marketing activities which was partially offset by an increase of $28 million in operating costs and expenses, exclusive of natural gas purchase costs, that resulted from our growth in volumes gathered. Volumes gathered grew to 900 Bcf in 2013 compared to 846 Bcf in 2012.

We had total capital investments of $7.4 billion in 2014, compared to $2.2 billion in 2013 and $2.1 billion in 2012. Of our total capital investments, $7.3 billion was invested in our E&P segment in 2014 which included $5.2 billion primarily related to the Chesapeake Property Acquisition compared to $2.1 billion in 2013 which included $96 million primarily related to the acquisition of properties in Northeast Appalachia and $1.9 billion in 2012.

Outlook

We believe the outlook for our business is favorable despite the continued uncertainty of natural gas and crude oil prices in the United States and the legislative and regulatory challenges facing our industry. Our resource base, financial strength and disciplined investment of capital provide us with an opportunity to exploit and develop our position through our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia divisions to maximize efficiency through economies of scale in our key operating areas, enhance our overall returns through our Midstream Services operations and grow through our E&P development activities. Our capital investment plan for 2015 is flexible and may be adjusted based on actual and expected natural gas and oil prices.

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RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand-alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense and income tax expense are discussed on a consolidated basis.

Exploration and Production

	For the year ended December 31,		
	2014	2013	2012
Revenues (in millions)	$2,862	$2,404	$1,964
Impairment of natural gas and oil properties (in millions)	$	$	$1,940
Operating costs and expenses (in millions)	$1,849	$1,525	$1,420
Operating income (loss) (in millions)	$1,013	$879	$(1,396)
Gain (loss) on derivatives(1) (in millions)	$9	$5	$(13)
Gas production (Bcf)	766	656	565
Oil production (MBbls)	235	138	83
NGL production (MBbls)	231	50	
Total production (Bcfe)	768	657	565
Average realized gas price per Mcf, including hedges (2)	$3.72	$3.65	$3.44
Average realized gas price per Mcf, excluding hedges	$3.74	$3.17	$2.34
Average oil price per Bbl	$79.91	$103.32	$101.54
Average NGL price per Bbl	$15.72	$43.63	$
Average unit costs per Mcfe:			
Lease operating expenses	$0.91	$0.86	$0.80
General & administrative expenses	$0.24	$0.24	$0.26
Taxes, other than income taxes	$0.11	$0.10	$0.10
Full cost pool amortization	$1.10	$1.08	$1.31

(1)Represents the gain (loss) on derivatives, settled, associated with derivatives not designated for hedge accounting.

(2)Including the gain (loss) on derivatives excluding derivatives, settled effects of commodity hedging contracts not designated for hedge accounting, results in an average price of $3.90, $3.68 and $3.43 for the year ended December 31, 2014, 2013 and 2012, respectively.

Revenues

Revenues for our E&P segment were up $458 million, or 19%, in 2014 compared to 2013. Higher natural gas production volumes in 2014 increased revenues by $403 million, and higher realized prices for our natural gas production increased revenue by $55 million compared to 2013. E&P revenues were up $440 million, or 22%, in 2013 compared to 2012. Higher natural gas production volumes in 2013 increased revenues by $316 million, higher realized prices for our natural gas production increased revenue by $118 million, and higher oil production volumes in

2013 increased revenues by $6 million compared to 2012. We expect our natural gas production volumes to continue to increase due to the development of our Northeast and Southwest Appalachia properties. Natural gas and oil prices are difficult to predict and are subject to wide price fluctuations. As of February 24, 2015, we had hedged 240 Bcf of our remaining 2015 natural gas production to help limit our exposure to price fluctuations. For more information about our derivatives and risk management activities, we refer you to Note 5 to the consolidated financial statements included in this Annual Report and to Commodity Prices below for additional information.

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Production

In 2014, our natural gas and oil production increased 17% to 768 Bcfe, up from 657 Bcfe in 2013. The 111 Bcfe increase in our 2014 production resulted from a 103 Bcf increase in net production from our Northeast Appalachia properties, and an 8 Bcf increase in net production from our Fayetteville Shale properties. In 2013, our natural gas and oil production increased to 657 Bcfe, up from 565 Bcfe in 2012. The 92 Bcfe increase in our 2013 production resulted from a 97 Bcf increase in net production from our Northeast Appalachia properties and a 2 Bcfe increase in net production in our New Ventures and Fayetteville Shale properties, which more than offset a combined 7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Our net production from the Fayetteville Shale was 494 Bcf in 2014, up from 486 Bcf in 2013 and 2012. Our net production from Northeast Appalachia was 254 Bcf in 2014, up from 151 Bcf in 2013 and 54 Bcf in 2012.

We are targeting 2015 natural gas and oil production of 940 to 955 Bcfe, an increase of approximately 23% over our 2014 production, using midpoints. Approximately 448 to 453 Bcf of our 2015 targeted natural gas production is projected to come from our activities in the Fayetteville Shale, 356 to 361 Bcf is projected to come from our activities in Northeast Appalachia and 136 to 141 Bcfe is projected to come from our activities in Southwest Appalachia. Although we expect production volumes in 2015 to increase, we cannot guarantee our success in discovering, developing and producing our total reserves. Our ability to discover, develop and produce reserves is dependent upon a number of factors, many of which are beyond our control, including the availability of capital, availability of transportation, weather, the timing and extent of changes in natural gas and oil prices and competition. There are also many risks inherent in the discovery, development and production of natural gas and oil. We refer you to Risk Factors in Item 1A of Part I of this Annual Report for a discussion of these risks and the impact they could have on our financial condition and results of operations.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, increased 2% to $3.72 per Mcf in 2014 and increased 6% to $3.65 per Mcf in 2013. The increase in the average price realized in 2014 compared to 2013 and the increase in 2013 compared to 2012 primarily reflects the increase in average market prices and to a lesser extent the decreased effect of our natural gas price hedging activities. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials. We refer you to Item 7A of this Annual Report, Note 5 to the consolidated financial statements, and our hedge risk factor for additional discussion about our derivatives and risk management activities.

Our hedging activities decreased the average natural gas sales price we realized by $0.02 per Mcf in 2014, compared to an increase of $0.48 per Mcf in 2013 and an increase of $1.10 per Mcf in 2012. Disregarding the impact of hedges, the average realized sales price we received for our natural gas production in 2014 was $0.57 per Mcf higher than 2013 and $0.67 lower than the average monthly NYMEX settlement price for 2014.

As of December 31, 2014, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 292 Bcf and 139 Bcf of our 2015 and 2016 production, respectively, and expected natural gas production through financial hedging activities and physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.13) per Mcf and ($0.08) per Mcf for 2015 and 2016, respectively.

In addition to the basis protection discussed above, as of December 31, 2014, we had NYMEX fixed price hedges in place on notional volumes of 240 Bcf of our 2015 natural gas production at an average price of $4.40 per MMBtu.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to locational basis differentials, transportation charges and fuel charges. Assuming a NYMEX commodity price of $3.25 per Mcf for 2015, and including the impact of financial basis hedges, we expect our total natural gas sales discount to NYMEX to be $0.70 to $0.85 per Mcf for 2015.

We realized an average sales price of $79.91 per barrel for our oil production for the year ended December 31, 2014, down approximately 23% from the prior year. The 2013 average realized price of $103.32 per barrel was up 2% from 2012. We did not hedge any of our 2014, 2013 or 2012 oil production.

We realized an average sales price of $15.72 per barrel for our NGL production for the year ended December 31, 2014, down approximately 64% from the $43.63 per barrel in 2013. We did not hedge any of our 2014, 2013, or 2012 NGL production.

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Operating Income

Our E&P segment operating income was $1,013 million in 2014, up from an operating income of $879 million in 2013. Operating income in 2014 increased $134 million over 2013 as the revenue impact of our 17%, or 111 Bcfe, increase in production and 2%, or $0.07, increase in our average realized natural gas prices more than offset the $324 million increase in operating costs and expenses that resulted from our significant production growth. E&P segment operating income was $879 million in 2013, up from an operating loss of $1,396 million in 2012. The operating loss in 2012 included a $1,940 million non-cash ceiling test impairment of our United States natural gas and oil properties. Excluding the $1,940 million non-cash ceiling test impairment, operating income in 2013 increased $335 million over 2012 as the revenue impact of our 16%, or 92 Bcfe, increase in production and the increase in our average realized natural gas price (6% or $0.21 per Mcf) more than offset the $105 million increase in operating costs that resulted from our significant production growth.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.91 in 2014, compared to $0.86 in 2013 and $0.80 in 2012. Lease operating expenses per unit of production increased in 2014 primarily due to increased gathering and compression costs associated with our Northeast Appalachia and Fayetteville Shale operations. Lease operating expenses per unit of production increased in 2013 compared to 2012 primarily due to increased gathering and compression costs associated with our Northeast Appalachia operations, offset slightly by decreased salt water disposal costs associated with our Fayetteville Shale operations. We expect our per unit lease operating cost to range between $0.90 and $0.95 per Mcfe in 2015.

General and administrative expenses for the E&P segment were $0.24 per Mcfe in 2014 and 2013, down from $0.26 per Mcfe in 2012. The decrease in general and administrative costs per Mcfe in 2013 was primarily due to a decrease in personnel costs per unit of production due to our significant increase in production in 2013. In total, general and administrative expenses for the E&P segment were $182 million in 2014, $157 million in 2013 and $145 million in 2012. The increase in general and administrative expenses in 2014 was primarily a result of increased personnel costs, information system related costs, and training costs, offset slightly by decreased professional fees. This net increase accounted for $22 million, or 88%, of the 2014 increase. The increase in general and administrative expenses in 2013 was primarily due to increased personnel costs and professional fees associated with the expansion of our E&P operations, offset slightly by decreased information system costs and bad debt expense. This net increase accounted for $11 million, or 89%, of the 2013 increase. We added 132 new E&P employees during 2014 compared to 159 employees added in 2013. We expect our per unit cost for general and administrative expenses in 2015 to range between $0.20 and $0.24 per Mcfe.

Taxes other than income taxes per Mcfe were $0.11 in 2014 and $0.10 in 2013, and 2012. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $1.10 per Mcfe for 2014, $1.08 per Mcfe for 2013 and $1.31 per Mcfe for 2012. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including, but not limited to, the uncertainty of the amount of future reserve changes.

Unevaluated costs excluded from amortization were $4.6 billion at the end of 2014 compared to $1 billion at the end of 2013 and 2012. Unevaluated costs excluded from amortization at the end of 2014 included $76 million related to our properties in Canada. The increase in unevaluated costs since December 31, 2013 primarily resulted from the Chesapeake Property Acquisition. See Note 4 to the consolidated financial statements for additional information regarding our unevaluated costs excluded from amortization.

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The timing and amount of production and reserve additions could have a material impact on our per unit costs; if production or reserves additions are lower than projected, our per unit costs could increase.

Midstream Services

	For the year ended December 31,		
	2014	2013	2012
	($ in millions, except volumes)		
Marketing revenues	$3,797	$2,830	$1,889
Gas gathering revenues	$562	$516	$474
Marketing purchases	$3,738	$2,783	$1,859
Operating costs and expenses	$260	$238	$210
Operating income	$361	$325	$294
Gas volumes marketed (Bcf)	904	786	676
Gas volumes gathered (Bcf)	963	900	846

Revenues

Revenues from our marketing activities were up 34% to $3.8 billion for 2014 compared to 2013. The increase in marketing revenues resulted from an increase in the prices received for volumes marketed and an increase in volumes marketed. Revenues from our marketing activities were up 50% to $2.8 billion for 2013 compared to 2012. The increase in marketing revenues resulted from an increase in the prices received for volumes marketed and an increase in volumes marketed. The average price received for volumes marketed increased 17% in 2014 compared to 2013, and increased 29% in 2013 compared to 2012. Volumes marketed increased 15% in 2014 compared to 2013, and increased 16% in 2013 compared to 2012. Of the total volumes marketed, production from our E&P operated wells accounted for 97% in 2014, 96% in 2013 and 95% in 2012. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in natural gas purchase expenses.

Revenues from our gathering activities were up 9% to $562 million for 2014 compared to 2013, and were up 9% to $516 million for 2013 compared to 2012. The increases in gathering revenues primarily resulted from a 7% increase in natural gas volumes gathered in 2014 compared to 2013 and a 6% increase in natural gas volumes gathered in 2013 compared to 2012. The majority of the increases in gathering revenues for 2014 and 2013 resulted from increases in the volumes gathered from our operated production in Northeast Appalachia.

Operating Income

Operating income from our Midstream Services segment increased 11% to $361 million in 2014 and increased 11% to $325 million in 2013. The increases in operating income reflect the substantial increases in natural gas volumes gathered and marketed which resulted primarily from our increased E&P production volumes. The increase in operating income for 2014 compared to 2013 was due to an increase of $46 million in gathering revenues and $12 million in the margin generated from our natural gas marketing activities, which was partially offset by a $22 million increase in operating costs and expenses, exclusive of purchased natural gas costs, associated with the increase in natural gas volumes gathered. The increase in operating income for 2013 compared to 2012 was due to a $42 million increase in gathering revenues and an increase of $17 million in the margin generated from our natural gas marketing activities, partially offset by a $28 million increase in operating costs and expenses, exclusive of purchased natural gas costs associated with the increase in natural gas volumes gathered.

The margin generated from natural gas marketing activities was $59 million for 2014, compared to $47 million for 2013 and $30 million for 2012. Margins are driven primarily by volumes of natural gas marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increases in margins generated are primarily the result of a 15% increase in volumes marketed in 2014 and an 16% increase in volumes marketed in 2013, as compared to prior years, resulting from the marketing of our increased E&P production volumes. We enter into hedging activities from time to time with respect to our natural gas marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to Quantitative and Qualitative Disclosures about Market Risk and Note 5 to the consolidated financial statements.

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Interest Expense

Interest expense, net of capitalization, was $59 million in 2014, an increase of $17 million compared to 2013, primarily due to our increased borrowing level. Interest capitalized was $55 million in 2014 compared to $62 million in 2013.

Interest expense, net of capitalization, was $42 million in 2013. The increase of $7 million compared to 2012 is primarily due to our increased borrowing level. Interest capitalized was to $62 million in 2013 and 2012.

Income Taxes

Our effective tax rate was 36%, 41%, and 39%, in 2014, 2013, and 2012, respectively. Our effective tax rate decreased in 2014 as compared to 2013 primarily due to a redetermination of the deferred state tax liability to reflect updated state apportionment factors in certain states. The effective tax rate was higher in 2013 primarily due to our increased development activities in the state of Pennsylvania, an increase in the impact of our state rates used in establishing deferred income taxes, and a valuation allowance placed against certain state net operating losses. In general, differences between our effective tax rate and the federal tax rate of 35% primarily result from the effect of certain state income taxes and permanent items attributable to book-tax differences.

Reconciliation of Non-GAAP Measures

We report our financial results in accordance with GAAP. However, management believes certain non-GAAP performance measures may provide users of this financial information additional meaningful comparisons between current results and the results of our peers and of prior periods.

Adjusted EBITDA is defined as net income plus interest, income tax expense, non-cash impairment of natural gas and oil properties, (gain) loss on derivatives excluding derivatives, settled, (gain) loss on asset sales and depreciation, depletion and amortization. Management presents measures such as adjusted EBITDA because it is used by many investors and it is a financial measure commonly used in the energy industry. Adjusted EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with GAAP, or as a measure of a company s profitability or liquidity. Adjusted EBITDA as defined above may not be comparable to similarly titled measures of other companies. The table below reconciles Adjusted EBITDA, as defined, with net income.

	E&P	Midstream Services (in millions)	Other	Total
2014				
Net income (loss)	$704	$224	$(4)	$924
Depreciation, depletion and amortization expense	884	58		942
(Gain) loss on derivatives excluding derivatives, settled	(131)	1		(130)
Net interest expense	47	12		59
Provision for income taxes	402	123		525
Adjusted EBITDA	$1,906	$418	$(4)	$2,320
2013				
Net income (loss)	$509	$196	$(1)	$704
Depreciation, depletion and amortization expense	735	51	1	787
Gain on derivatives excluding derivatives, settled	(21)			(21)
Net interest expense	30	11	1	42
Provision (benefit) for income taxes	368	119	(1)	486
Adjusted EBITDA	$1,621	$377	$	$1,998
2012				
Net income (loss)	$(884)	$176	$1	$(707)
Depreciation, depletion and amortization expense	766	44	1	811
Impairment of natural gas and oil properties	1,940			1,940
Loss on derivatives excluding derivatives, settled	2			2
Net interest expense	20	14	1	35
Provision (benefit) for income taxes	(549)	105	1	(443)
Adjusted EBITDA	$1,295	$339	$4	$1,638

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally generated funds, our $2.0 billion revolving credit facility and funds accessed through capital markets as our primary sources of liquidity.

During 2015, depending on natural gas prices, we may draw on a portion of the funds available under our revolving credit facility to fund the portion of our planned capital investments exceeding our operating cash flow (discussed below under Capital Investments). We refer you to Note 8 to the consolidated financial statements included in this Annual Report and the section below under Financing Requirements for additional discussion of our revolving credit facility.

As of December 31, 2014, our capital structure consisted of 60% debt and 40% equity. We believe that our operating cash flow and available funds under our revolving credit facility will be adequate to meet our capital and operating requirements for 2015. The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving credit facility. Although we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will meet its obligation.

Net cash provided by operating activities increased 22% to $2.3 billion in 2014, due to an increase in net income adjusted for non-cash expenses and changes in working capital accounts. Net cash provided by operating activities increased 15% to $1.9 billion in 2013 over 2012 due to an increase in net income adjusted for non-cash expenses which was partially offset by changes in working capital accounts. For 2014, requirements for our capital investments were funded from our cash generated by operating activities, cash and cash equivalents, and net proceeds from borrowings under our revolving credit facility, bridge facility and term loan facility. Net cash from operating activities provided 31% of our cash requirements for capital investments in 2014, 85% in 2013 and 78% in 2012.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our natural gas and oil production. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See Risk Factors in Item 1A for further details. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and partners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and partners could adversely impact our cash flows.

Due to the above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we will adjust our discretionary uses of cash dependent upon available cash flow.

Capital Investments

Our capital investments were $7.4 billion in 2014, compared to $2.2 billion in 2013 and $2.1 billion in 2012. Capital investments include an increase of $155 million in 2014, a decrease of $25 million in 2013 and a decrease of $37 million in 2012 related to the change in accrued expenditures between years. Our E&P segment investments in 2014 were $7.3 billion which included $5.2 billion primarily related to the Chesapeake Property Acquisition compared to $2.1 billion in 2013 which included $96 million primarily related to the acquisition of properties in Northeast Appalachia and $1.9 billion in 2012.

	Capital investments for the year ended December 31,		
	2014	2013	2012
		(in millions)	
Exploration and production	$2,021	$ 1,956	$1,861
Acquisitions	5,233	96	
Midstream Services	144	158	165
Other	49	25	55
	$7,447	$ 2,235	$2,081

Excluding the capital associated with the closing of the WPX and Statoil Property Acquisitions, our capital investments for 2015 are planned to be $2.0 billion, consisting of approximately $1.9 billion for E&P, $85 million for Midstream Services and $40 million for E&P services and corporate. Of the approximately $1.9 billion, we expect to allocate approximately $560 million to our Fayetteville Shale properties, approximately $700 million to our Northeast Appalachia properties, and approximately $520 million to our Southwest Appalachia properties. Our planned level of capital investments in 2015 is expected to allow us to continue our progress in the Fayetteville Shale and Northeast Appalachia programs, initiate our development program in Southwest Appalachia and explore and develop other existing natural gas and oil properties and generate new drilling prospects. Our 2015 capital investment program is expected to be funded through cash flow from operations and borrowings under our revolving credit facility. The planned capital program for 2015 is flexible, and we will reevaluate our proposed investments needed to take into account prevailing market conditions.

Financing Requirements

Our total debt outstanding was $7.0 billion as of December 31, 2014, compared to $2.0 billion at December 31, 2013.

On December 19, 2014, we entered into a $4.5 billion unsecured 364-day bridge term loan credit agreement with various lenders. The bridge facility required prepayments under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business or for specified uses. We repaid the $4.5 billion outstanding and terminated the bridge facility in January 2015 with net proceeds of $669 million and $1.7 billion

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from common stock and depositary share offerings, respectively, and $2.2 billion from senior note offerings with the difference utilized to pay down amounts under our revolving credit facility.

On December 19, 2014, we also entered into a $500 million unsecured two-year term loan credit agreement with various lenders. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business.

In December 2013, we entered into a credit agreement that exchanged our previous revolving credit facility. Under the revolving credit facility, we have a borrowing capacity of $2.0 billion. The new revolving credit facility has a maturity date of December 2018 and options for two one-year extensions with participating lender approval. The amount available under the revolving credit facility may be increased by $500 million upon our agreement with its participating lenders. The interest rate on the revolving credit facility is calculated based upon our debt rating and is currently 150 basis points over the current London Interbank Offered Rate, or LIBOR. The borrowing rate on our revolving credit facility was 150 basis points over LIBOR as of December 31, 2013. The revolving credit facility is unsecured and is not guaranteed by any of our subsidiaries. Contemporaneously with the execution of the credit agreement, in December 2013, we obtained releases of subsidiary guarantees under the 7.15%, 7.5%, 7.35%, 7.125% and 4.10% senior notes.

At February 24, 2015, we have a long-term issuer credit rating of BBB- by Standard and Poor s ratings, BBB- by Fitch ratings and we have a long-term credit rating of Baa3 by Moody s. Any downgrades in our public debt ratings could increase our cost of funds under our revolving credit facility.

Our revolving credit facility, bridge facility (which was fully repaid in January 2015) and term loan facility contain covenants which impose certain restrictions on us. Under our revolving credit facility, bridge facility and term loan facility we must keep our total debt at or below 60% of our total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the noncontrolling interest in equity, the effects of any non-cash impacts from any full cost ceiling impairments (beginning in the year ended December 31, 2011), certain non-cash hedging activities and our pension and other postretirement liabilities. Therefore, under our revolving credit facility, bridge facility and term loan facility provisions, our adjusted capital structure as of December 31, 2014 was 55% debt and 45% equity. We were in compliance with all of the covenants of our revolving credit facility, bridge facility and term loan facility as of December 31, 2014. Although we do not anticipate any violations of our financial covenant, our ability to comply with this covenant is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our revolving credit facility, we may have to decrease our capital investment plans.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At February 24, 2015, we had NYMEX commodity price hedges in place on 240 Bcf, or approximately 27% of our targeted 2015 production. The amount of our debt will be dependent upon commodity prices and our capital investment plans.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2014, our material off-balance sheet arrangements and transactions include operating lease arrangements. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to Contractual Obligations and Contingent Liabilities and Commitments below.

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Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations as of December 31, 2014, were as follows:

Contractual Obligations:

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
	(in millions)				
Transportation charges(1)	$5,389	$478	$1,058	$1,051	$2,802
Debt	6,968	4,501 (6)	542	925	1,000
Interest on debt(2)	514	103	198	110	103
Operating leases(3)	272	73	107	47	45
Compression services(4)	102	41	47	14	-
Operating agreements	123	121	2	-	-
Purchase obligations	54	54	-	-	-
Other obligations(5)	756	188	51	16	501
	$14,178	$5,559	$2,005	$2,163	$4,451

(1)As of December 31, 2014, our Midstream Services segment had commitments for demand transportation charges on various pipelines, including approximately $1.1 billion related to the ATEX pipeline, $899 million related to the Rover pipeline, $644 million related to the FEP pipeline, $506 million related to the Tennessee Gas pipeline, $469 million related to the Constitution pipeline, $399 million related to Boardwalk pipeline and $208 million related to the Millenium pipeline. We also had approximate commitments of $500 million related to the Susquehanna Gathering Company I, LLC s construction of gathering infrastructure in Susquehanna County, Pennsylvania to provide gathering services to SES in support of a portion of our future Marcellus Shale natural gas production and $280 million associated with Bluestone Gathering Company.

(2) Interest payments on our senior notes were calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2014. Interest payments on the revolving credit facility were calculated by assuming that the December 31, 2014 outstanding balance of $300 million will be outstanding through the December 2018 expiration date. Interest payments on the term loan facility were calculated by assuming that the December 31, 2014 outstanding balance of $500 million will be outstanding through the December 2016 expiration date. A constant rate of 1.515% and 1.545%, the rate as of December 31, 2014, was assumed for the revolving credit facility and term loan facility, respectively. Interest payments for the $4.5 billion bridge facility were not included in the above table as the balance was repaid in full with proceeds from the January 2015 financing transactions.

(3)Operating leases include costs for compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2027. Additionally, this includes $23 million for pressure pumping equipment for E&P operations through 2018.

(4)As of December 31, 2014, our Midstream Services segment had commitments of approximately $97 million and our E&P segment had commitments of approximately $5 million for compression services associated primarily with our Fayetteville and Southwest Appalachia divisions.

(5)Our other significant contractual obligations include approximately $561 million for asset retirement obligations primarily relating to natural gas and oil properties, approximately $137 million associated with the construction of our new corporate campus, approximately $12 million for funding of benefit plans, approximately $14 million for various information technology support and data subscription agreements, and approximately $7 million for insurance premium financing.

(6) As of December 31, 2014, total debt outstanding included $4.5 billion related to our bridge facility. We repaid the $4.5 billion and terminated our bridge facility in January 2015.

We refer you to Note 8 to the consolidated financial statements for a discussion of the terms of our debt.

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Commitments and Contingent Liabilities

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. We currently expect to contribute approximately $12 million to our pension plans and $0.6 million to our postretirement benefit plan in 2015. For 2014, we contributed $12 million to our pension plans and contributed $0.1 million to our postretirement benefit plan. As of December 31, 2014 we recognized a liability of $44 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $16 million at December 31, 2013. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 12 to the consolidated financial statements and Critical Accounting Policies and Estimates below for additional information.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described in Financing Requirements above. We had negative working capital of $4.3 billion as of December 31, 2014 and negative working capital of $44 million at December 31, 2013. The negative working capital as of December 31, 2014 was driven by the outstanding balance on our bridge facility, which was repaid in full in January 2015. Current assets increased $471 million during 2014 primarily due to a $266 million increase in our current derivative asset, a $110 million increase in other current assets, a $66 million increase in accounts receivable, and a $30 million increase in cash, which was partially offset by a $1 million decrease in inventory. Current liabilities increased $4.7 billion primarily due to a $4.5 billion increase in our short-term debt incurred under our bridge facility, a $146 million increase in accounts payable, a $85 million increase in our current deferred income taxes, a $24 million increase in taxes payable, a $2 million increase in our derivative liability, and a $1 million increase interest payable, which partially was offset by a $18 million decrease in other current liabilities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We evaluate our estimates on an on-going basis, based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following describes significant judgments and estimates used in the preparation of our consolidated financial statements.

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10% (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.35 per MMBtu, West Texas Intermediate oil of $91.48 per barrel, and NGLs of $23.79 per barrel, adjusted for market differentials, the net book value of our United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2014. Cash flow hedges of natural gas production in place increased this ceiling amount by approximately $3.6 million as of December 31, 2014. At December 31, 2013, the ceiling value of our reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months of $3.67 per MMBtu for Henry Hub natural gas, West Texas Intermediate oil of $93.42 per barrel, and NGLs of $43.45 per barrel. At December 31, 2012, the ceiling value of our reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.76 per MMBtu and for West Texas Intermediate oil of $91.21. Using the first-day-of-the-month prices of natural gas for the first two months of 2015 and NYMEX strip prices for the remainder of 2015, as applicable, the prices required to be used to determine the ceiling limit could result in a ceiling test write-down in 2015. Decreases in market prices as well as changes

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in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments. During 2012, the net capitalized costs of our United States natural gas and oil properties exceeded the ceiling by approximately $1,192 million (net of tax) and resulted in a non-cash ceiling test impairment.

A decline in natural gas and oil prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves. Our reserve base is approximately 91% natural gas and historically has been closer to 100%; therefore changes in oil prices used do not have as significant an impact as natural gas prices on cash flows and reserve quantities. Our standardized measure and reserve quantities as of December 31, 2014, were $7.5 billion and 10.7 Tcfe, respectively.

All of our costs directly associated with the acquisition and evaluation of properties in Canada relating to its exploration program as of December 31, 2014 and as of December 31, 2013 were unproved and did not exceed the ceiling amount. If the exploration program in Canada is unsuccessful on all or a portion of these properties, including the effects of changes in laws or regulations due to the new government in New Brunswick or otherwise or our exploration licenses in New Brunswick are not renewed in the first quarter of 2015, a ceiling test impairment may result in the future. We commenced our Canada exploration program in 2010 and, as of December 31, 2014 we have invested $45 million Canadian dollars, or $44 million USD, in New Brunswick.

Natural gas and oil reserves cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and projections of cost that will be incurred in developing and producing reserves and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team to which the property is assigned. The reservoir engineering and financial data included in these estimates are reviewed by senior engineers who are not part of the asset management teams and by our Reservoir Supervisor - Reserves, who is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Reservoir Supervisor Reserves has more than 28 years of experience in petroleum engineering, including the estimation of oil and natural gas reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2009, our Reservoir Supervisor - Reserves served in various reservoir engineering roles for Citation Oil & Gas Corporation, Mitchell Energy & Development Corporation, Whites Stone Energy and H.J. Gruy & Associates and is a member of the Society of Petroleum Engineers and Society of Petroleum Evaluation Engineers and is a Licensed Professional Engineer in the state of Texas. He reports to our Vice President and General Manager Strategy, Performance and Innovation who has more than 28 years of experience in reservoir engineering including the estimation of oil and natural gas reserves in multiple basins in the United States. Prior to joining Southwestern in 1993, our Vice President and General Manager Strategy, Performance and Innovation served in various engineering roles for Conoco Inc and is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers, American Institute of Professional Geologists, IPAA and TIPRO. He is also a Licensed Professional Engineer in the state of Texas. On our behalf, the Vice President and General Manager Strategy, Performance and Innovation engages NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates as discussed in more detail below. The financial data included in the reserve estimates are also separately reviewed by our accounting staff. Following these reviews and the audit, the reserve estimates is submitted by our Vice President and General Manager Strategy, Performance and Innovation to our Chief Executive Officer for his review and approval prior to the presentation to our Board of Directors. NSAI reports the results of its reserve audit to the Board of Directors, with whom final authority over the estimates of our proved reserves rests.

Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves accounted for 55% of our total reserve base as of December 31, 2014. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate in Item 1A, Risk Factors, of Part I of this Annual Report for a more detailed discussion of these uncertainties, risks and other factors.

In conducting its audit, the engineers and geologists of NSAI study our major properties in detail and independently develop reserve estimates. NSAI s audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 97% of the present worth of the company s total proved reserves. NSAI s

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audit process consists of sorting all fields by descending present value order and selecting the fields from highest value to descending value until the selected fields account for more than 80% of the present worth of our reserves. The properties in the bottom 20% of the total present worth are not reviewed in the audit. The fields included in approximately the top 97% present value as of December 31, 2014, accounted for approximately 98% of our total proved reserves and approximately 100% of our proved undeveloped reserves. In the conduct of its audit, NSAI did not independently verify the data we provided to them with respect to ownership interests, oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. NSAI has advised us that if, in the course of its audit, something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved any questions relating thereto or had independently verified such information or data. On January 16, 2015, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2014, stating that our estimated proved oil and natural gas reserves are, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Business combinations

We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved oil and natural gas properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of reserves, future operating and development costs, future commodity prices and a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of oil and natural gas properties within the same regions, and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into in exchange for such properties. Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain on bargain purchase. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities.

The Chesapeake Property Acquisition qualified as a business combination, and as such, we estimated the fair value of the assets acquired and liabilities assumed as of the December 22, 2014 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. We used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as defined in Note 7 Fair Value. We recorded the assets acquired and liabilities assumed in the Chesapeake Property Acquisition at their estimated fair value of approximately $5.0 billion, which we consider to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized.

Hedging

We use natural gas agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. In 2012, 2013, and 2014 we hedged 47%, 44% and 60% of our production, respectively. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas. However, the market price risk is generally offset by the gain or loss recognized upon the related natural gas transaction that is hedged.

Our derivative instruments are recorded at fair value in our consolidated financial statements and generally qualify for hedge accounting. We have established the fair value of derivative instruments using data provided by our counterparties in conjunction with assumptions evaluated internally using established index prices and other sources. These valuations are recognized as assets or liabilities on our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production, the offset is recorded in other comprehensive income. Results of settled commodity derivative transactions that qualify for hedge accounting are reflected in gas sales. Any derivative not designated for hedge accounting treatment or any ineffective portion of a properly designated hedge is recognized immediately in earnings. As of December 31, 2014, our fixed price basis swaps and fixed price call options were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the year ended December 31, 2014, we recorded a gain on derivatives of $124 million related to fixed price swaps not designated for hedge accounting, a gain on derivatives of $18 million related to fixed price call options that were not designated for hedge accounting treatment and a gain on derivatives of $5 million related to the basis swaps that were not designated for hedge account treatment. Also recorded in gain (loss) on derivatives at December 31, 2014 was a loss of $8 million related to our interest rate swap.

In general and without consideration of volatility or duration, if 2015 and 2016 natural gas prices increase from current levels, we will recognize losses in future periods and, likewise, if 2015 and 2016 natural gas prices decline from current levels, we will recognize gains in future periods on our derivative contracts not accounted for under hedge accounting prior to settlement. Future market price volatility could create significant changes to the hedge positions recorded in our consolidated financial statements. We refer to you to Quantitative and Qualitative Disclosures about Market Risk in Item 7A of Part II of this Annual Report for additional information regarding our hedging activities.

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 12 to the consolidated financial statements for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2014 benefit obligation and periodic benefit cost to be recorded in 2015, the discount rate assumed is 4.25% and 5.00%, respectively. This compares to a discount rate of 5.00% and 4.00% for the benefit obligation and periodic benefit cost recorded in 2014, respectively. For the 2015 periodic benefit cost, the expected return assumed is 7.00%, compared to an expected return of 7.00% in 2014.

Using the assumed rates discussed above, we recorded total benefit cost of $15 million in 2014 related to our pension and other postretirement benefit plans. Due to the significance of the discount rate and expected long-term rate of return, the following sensitivity analysis demonstrates the effect that a 50 basis point change in those assumptions would have had on our 2014 pension expense:

	Increase (Decrease) of Annual Pension Expense	
	50 Basis Point Increase	50 Basis Point Decrease
	(in millions)	
Discount rate	$ (1)	$1
Expected long-term rate of return	$ (1)	$1

As of December 31, 2014, we recognized a liability of $44 million, compared to $16 million at December 31, 2013, related to our pension and other postretirement benefit plans. During 2014, we also made cash payments totaling $12 million to fund our pension and other postretirement benefit plans. In 2015, we expect to make cash payments totaling $12 million to fund our pension and other postretirement benefit plans and recognize pension expense of $16 million and a postretirement benefit expense of $4 million.

Asset Retirement Obligations

We own natural gas and oil properties, which require expenditures to plug and abandon the wells when reserves in the wells are depleted. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The recognition of asset retirement obligations requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rate, all of which are subject to change.

Stock-Based Compensation

We account for stock-based compensation transactions using a fair value method and recognize an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalize the cost into natural gas and oil properties or gathering systems included in property and equipment. Costs are capitalized

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when they are directly related to the acquisition, exploration and development activities of our natural gas and oil properties or directly related to the construction of our gathering systems. We use models to determine fair value of stock-based compensation, which requires significant judgment with respect to forfeitures, volatility and other factors. If any of the assumptions change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period.

New Accounting Standards Not Yet Implemented in this Report

Refer to Note 1 to the consolidated financial statements of this Annual Report for further discussion of our significant accounting policies and for discussion of accounting standards not yet implemented.

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Annual Report identified by words such as anticipate, project, intend, estimate, expect, believe, predict, budget, projection, goal, plan, f expressions.

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

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to fund our planned capital investments;
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the economic viability of, and our success in drilling, our large acreage positions in the Fayetteville Shale, Northeast Appalachia and Southwest Appalachia overall as well as relative to other productive shale gas plays;
- our ability to realize the expected benefits from the properties recently acquired in the Acquisitions;
- the impact of title and environmental defects and other matters on the value of the properties acquired in the Acquisitions and any other future acquisitions;
- difficulties in integrating our operations as a result of any significant acquisitions, including the Acquisitions;
- the impact of government regulation, including the ability to obtain and maintain permits, any increase in severance or similar taxes, and legislation relating to hydraulic fracturing, climate and over-the-counter derivatives;
-

the costs and availability of oilfield personnel, services and drilling supplies, raw materials, and equipment, including pressure pumping equipment and crews;

- our ability to determine the most effective and economic fracture stimulation;
- our future property acquisition or divestiture activities;
- the impact of the adverse outcome of any material litigation against us;
- the effects of weather;
- increased competition and regulation;

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- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- the different risks and uncertainties associated with Canadian exploration and production;
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that forward-looking statements contained in this Annual Report are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in Item 1A of Part I of this Annual Report.

Estimates of our proved natural gas and oil reserves and the estimated future net revenues from such reserves in this Annual Report are based upon various assumptions, including assumptions required by the SEC relating to natural gas and oil prices, drilling and operating expenses, capital investments, taxes and availability of funds. The process of estimating natural gas and oil reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, those estimates are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development costs, operating expenses and quantities of recoverable natural gas and oil reserves will most likely vary from those estimated. Such variances may be material. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this Annual Report. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

As of December 31, 2014, approximately 45% of our estimated proved reserves were proved undeveloped and 2% were proved developed non-producing. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimates of reserves in the non-producing categories are nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Recovery of proved developed non-producing reserves requires capital expenditures to recomplete into the zones behind pipe and is subject to the risk of a successful recompletion. Production revenues from proved undeveloped and proved developed non-producing reserves will not be realized, if at all, until sometime in the future.

The reserve data assumes that we will make significant capital investments to develop our reserves. Although we have prepared estimates of our natural gas and oil reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

You should not assume that the present value of future net cash flows referred to in this Annual Report is the current fair value of our estimated natural gas and oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on average prices over the preceding twelve months and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the average prices and costs as of the date of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation could also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for our company.

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas fixed price swap agreements, fixed price options, basis swaps and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is subject to the approval of our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our purchasers and their dispersion across geographic areas. No single purchaser accounted for greater than 10% of revenues as of December 31, 2014. See Commodities Risk below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

The following table presents the principal cash payments for our debt obligations and related weighted-average interest rates by expected maturity dates as of December 31, 2014. As of December 31, 2014, we had $1,667 million of outstanding senior notes with a weighted average interest rate of 5.45%, $4.5 billion of short-term debt with a weighted average interest rate of 1.52%, $500 million of term loan facility debt with a weighted average interest rate of 1.55%, and $300 million of borrowings under our revolving credit facility with a weighted average interest rate of 1.52%. We currently have an interest rate swap in effect to mitigate our exposure to volatility in interest rates.

	Expected Maturity Date							Fair Value
	2015	2016	2017	2018	2019	Thereafter	Total	12/31/14
Fixed Rate Payments	$1	$1	$41	$624	$	$1,000	$1,667	$1,751
Weighted Average Interest Rate	7.15 %	7.15 %	7.21 %	7.49 %	%	4.10 %	5.45 %	
Variable Rate Payments	$4,500	$500	$	$300	$	$	$5,300	$5,300
Weighted Average Interest Rate	1.52 %	1.55 %	%	1.52 %	%	%	1.52 %	

Commodities Risk

We use over-the-counter natural gas and oil fixed price swap agreements and fixed price options to hedge sales of our production against the inherent risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps) and (3) the purchase and sale of index-related puts and calls (collars) that provide a floor price, below which the counterparty pays funds equal to the amount by which the price of the commodity is below the contracted floor, and a ceiling price above which we pay to the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or

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purchase of the natural gas that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major commercial banks, investment banks and integrated energy companies that management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, we cannot be certain that we will not experience such losses in the future.

Exploration and Production

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates.

	Volume (Bcf)	Weighted Average Price to be Swapped ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at December 31, 2014 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2015	240	$ 4.40	$	$	$	$ 328
Basis Swaps:						
2015	22	$	$	$	$ 0.05	$ 4
2016	4	$	$	$	$ 0.72	$
Fixed Price Call Options:						
2015	200	$	$ 5.09	$	$	$ (2)
2016	120		5.00			(10)

As of December 31, 2014, our basis swaps, certain fixed price swaps, fixed price call options, and interest rate swap were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the year ended December 31, 2014, we recorded a gain on derivatives excluding derivatives, settled of $126 million related to fixed price swaps not designated for hedge accounting, a gain on derivatives excluding derivatives, settled of $18 million related to fixed price call options not designated for hedge accounting, a loss on derivatives excluding derivatives, settled of $7 million related to basis swaps not designated for hedge accounting, and a loss on derivatives excluding derivatives, settled of $7 million related to our interest rate swap not designated for hedge accounting.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Management s Report on Internal Control Over Financial Reporting

It is the responsibility of the management of Southwestern Energy Company to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management has assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2014, utilizing the Committee of Sponsoring Organizations of the Treadway Commission s Internal Control Integrated Framework (2013).

Management has excluded the oil and gas assets acquired from a subsidiary of Chesapeake Energy Corporation in West Virginia and southwest Pennsylvania (Chesapeake Property Acquisition) from its assessment of internal control over financial reporting as of December 31, 2014 as the Chesapeake Property Acquisition was acquired in a business combination during 2014. The total assets and total revenues of the Chesapeake Property Acquisition represent approximately 33% and 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.

Based on this evaluation, management concluded the Company s internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwestern Energy Company

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Southwestern Energy Company and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

As described in Management s Report on Internal Control Over Financial Reporting, management has excluded the oil and gas properties acquired from a subsidiary of Chesapeake Energy Corporation in West Virginia and southwest Pennsylvania (Chesapeake Property Acquisition) from its assessment of internal control over financial reporting as of December 31, 2014 because it was acquired by the Company in a purchase business combination during 2014. We have also excluded the Chesapeake Property Acquisition from our audit of internal control over financial reporting. The Chesapeake Property Acquisition s total assets and total revenues represent 33% and 1% respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.

/s/PRICEWATERHOUSECOOPERS LLP

Houston, TX

February 26, 2015

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the years ended December 31		
	2014	2013	2012
	(in millions, except share/per share amounts)		
Operating Revenues:			
Gas sales	$2,827	$2,381	$1,956
Oil sales	22	16	8
Marketing	996	792	592
Gas gathering	193	182	174
	4,038	3,371	2,730
Operating Costs and Expenses:			
Marketing purchases	980	782	592
Operating expenses	427	328	245
General and administrative expenses	221	191	175
Depreciation, depletion and amortization	942	787	811
Impairment of natural gas and oil properties			1,940
Taxes, other than income taxes	95	79	68
	2,665	2,167	3,831
Operating Income (Loss)	1,373	1,204	(1,101)
Interest Expense:			
Interest on debt	101	100	93
Other interest charges	13	4	4
Interest capitalized	(55)	(62)	(62)
	59	42	35
Other Income (Loss), Net	(4)	2	1
Gain (Loss) on Derivatives	139	26	(15)
Income (Loss) Before Income Taxes	1,449	1,190	(1,150)
Provision (Benefit) for Income Taxes:			
Current	21	(11)	19
Deferred	504	497	(462)
	525	486	(443)
Net Income (Loss)	$924	$704	$(707)
Earnings (Loss) Per Share:			
Basic	$2.63	$2.01	$(2.03)
Diluted	$2.62	$2.00	$(2.03)
Weighted Average Common Shares Outstanding:			
Basic	351,446,747	350,465,430	348,610,503
Diluted	352,410,683	351,101,452	348,610,503

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

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	For the years ended December 31,		
	2014	2013	2012
	(in millions)		
Net income (loss)	$924	$704	$(707)
Change in derivatives:			
Settlements (1)	16	(185)	(382)
Ineffectiveness (2)		1	(1)
Change in fair value of derivative instruments (3)	73	22	131
Total change in derivatives	89	(162)	(252)
Change in value of pension and other postretirement liabilities:			
Current period net gain (loss) (4)	(15)	11	(7)
Amortization of prior service cost included in net periodic pension cost (5)		1	1
Total change in value of pension and other postretirement liabilities	(15)	12	(6)
Change in currency translation adjustment	(8)	(4)	
Comprehensive income (loss)	$990	$550	$(965)

(1) Net of $10, $(124), and $(249) million in taxes for the years ended December 31, 2014, 2013 and 2012, respectively.

(2) Net of $0, $1, and $(1) million in taxes for the years ended December 31, 2014, 2013 and 2012, respectively.

(3) Net of $49, $16, and $85 million in taxes for the years ended December 31, 2014, 2013 and 2012, respectively.

(4) Net of $(10), $8, and $(5) million in taxes for the years ended December 31, 2014, 2013 and 2012, respectively.

(5) Net of $0, $1, and $1 million in taxes for the years ended December 31, 2014, 2013, and 2012, respectively.

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

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
ASSETS	(in millions)	
Current assets:		
Cash and cash equivalents	$ 53	$ 23
Accounts receivable	530	464
Inventories	37	38
Derivative assets	337	71
Other current assets	158	48
Total current assets	1,115	644
Natural gas and oil properties, using the full cost method, including $4,646 million in 2014 and $957 million in 2013 excluded from amortization	20,506	13,294
Gathering systems	1,439	1,306
Other	612	703
Less: Accumulated depreciation, depletion and amortization	(8,845)	(8,006)
Total property and equipment, net	13,712	7,297
Other long-term assets	98	107
TOTAL ASSETS	$ 14,925	$ 8,048
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term debt	$ 4,501	$ 1
Accounts payable	653	507
Taxes payable	92	68
Interest payable	34	33
Current deferred income taxes	109	24
Derivative liabilities	9	7
Other current liabilities	30	48
Total current liabilities	5,428	688
Long-term debt	2,466	1,950
Deferred income taxes	1,951	1,532
Pension and other postretirement liabilities	44	16
Other long-term liabilities	374	240
Total long-term liabilities	4,835	3,738
Commitments and contingencies (see Note 9)		
Equity:		
Common stock, $0.01 par value; authorized 1,250,000,000 shares; issued 354,488,992 shares in 2014 and 352,938,584 in 2013	4	4
Additional paid-in capital	1,019	969
Retained earnings	3,577	2,653
Accumulated other comprehensive income (loss)	62	(4)
Common stock in treasury, 11,055 shares in 2014 and 9,924 in 2013		
Total equity	4,662	3,622
TOTAL LIABILITIES AND EQUITY	$ 14,925	$ 8,048

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the twelve months ended December 31,		
	2014	2013	2012
	(in millions)		
Cash Flows From Operating Activities			
Net income (loss)	$924	$704	$(707)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	942	787	811
Amortization of debt issuance cost	10	4	4
Impairment of natural gas and oil properties			1,940
Deferred income taxes	504	497	(462)
(Gain) loss on derivatives, net of settlement	(130)	(21)	2
Stock-based compensation	18	13	12
Other	2	1	
Change in assets and liabilities:			
Accounts receivable	(66)	(86)	(36)
Inventories	1	(6)	18
Accounts payable	84	74	41
Taxes payable	24	5	22
Interest payable		(1)	5
Advances from partners		(69)	(15)
Other assets and liabilities	22	7	19
Net cash provided by operating activities	2,335	1,909	1,654
Cash Flows From Investing Activities			
Capital investments	(2,043)	(2,157)	(2,108)
Acquisition of oil and gas properties	(5,298)	(96)	
Proceeds from sale of property and equipment	43	18	201
Transfers to restricted cash		9	(168)
Transfers from restricted cash			159
Other	10	10	9
Net cash used in investing activities	(7,288)	(2,216)	(1,907)
Cash Flows From Financing Activities			
Payments on current portion of long-term debt	(1)	(1)	(1)
Payments on revolving long-term debt	(5,179)	(3,148)	(2,264)
Borrowings under revolving long-term debt	5,196	3,430	1,592
Change in bank drafts outstanding	11	(7)	(36)
Proceeds from issuance of long-term debt	500		999
Proceeds from issuance of short-term debt	4,500		
Debt issuance costs	(56)		(8)
Proceeds from exercise of common stock options	12	10	9
Other		(7)	
Net cash provided by financing activities	4,983	277	291

Effect of exchange rate changes on cash		(1)	
Increase (decrease) in cash and cash equivalents	30	(31)	38
Cash and cash equivalents at beginning of year	23	54	16
Cash and cash equivalents at end of period	$53	$23	$54

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

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Southwestern Energy Stockholders						
	Common Stock		Additional		Accumulated other	Common	
	Shares Issued	Amount	Paid-In Capital	Retained Earnings	Comprehensive Income (Loss)	Stock in Treasury	Total
	(in millions, except share amounts)						
Balance at December 31, 2011	349,058,501	$ 4	$ 903	$ 2,656	$ 408	$ (2)	$ 3,969
Comprehensive loss:							
Net loss				(707)			(707)
Other comprehensive loss					(258)		(258)
Total comprehensive loss							(965)
Stock-based compensation			22				22
Exercise of stock options	1,607,784		9				9
Issuance of restricted stock	539,542						
Cancellation of restricted stock	(95,302)						
Tax withholding stock compensation	(11,357)						
Issuance of stock awards	1,223						
Treasury stock non-qualified plan						1	1
Balance at December 31, 2012	351,100,391	$ 4	$ 934	$ 1,949	$ 150	$ (1)	$ 3,036
Comprehensive loss:							
Net income				704			704
Other comprehensive loss					(154)		(154)
Total comprehensive income							550
Stock-based compensation			25				25
Exercise of stock options	833,132		10				10
Issuance of restricted stock	1,102,926						
Cancellation of restricted stock	(74,083)						
Tax withholding stock compensation	(25,131)		(1)				(1)
Issuance of stock awards	1,349						
Treasury stock non-qualified plan			1			1	2
Balance at December 31, 2013	352,938,584	$ 4	$ 969	$ 2,653	$ (4)	$	$ 3,622
Comprehensive income:							
Net income				924			924
Other comprehensive income					66		66
Total comprehensive income							990
Stock-based compensation			38				38
Exercise of stock options	402,190		12				12
Issuance of restricted stock	1,299,367						
Cancellation of restricted stock	(140,703)						
Tax withholding stock compensation	(12,133)						
Issuance of stock awards	1,687						

Balance at December 31, 2014	354,488,992	$ 4	$ 1,019	$ 3,577	$ 62	$	$ 4,662

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

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Southwestern Energy Company (including its subsidiaries, collectively Southwestern or the Company) is an independent energy company engaged in natural gas and oil exploration, development and production (E&P). Our current operations are principally focused within the United States on development of two unconventional natural gas reservoirs located in Arkansas and Pennsylvania. The Company s operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale, and its operations in northeast Pennsylvania are focused on an unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as Northeast Appalachia). Recently, the Company acquired a significant stake in properties located in West Virginia and southwest Pennsylvania which it also intends to develop. These operations in West Virginia are also focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as Southwest Appalachia). Collectively, the Company s properties located in West Virginia and Pennsylvania are herein referred to as the Appalachian Basin. To a lesser extent, the Company has exploration and production activities ongoing in Colorado, Louisiana, Texas and in the Arkoma Basin in Arkansas and Oklahoma. The Company also actively seeks to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which it refers to as New Ventures, and through acquisitions. The Company also operates drilling rigs in Arkansas and Pennsylvania, as well as in other operating areas, and provide oilfield products and services, principally serving its exploration and production operations. Southwestern s natural gas gathering and marketing (Midstream Services) activities primarily support the Company s E&P activities in Arkansas, Texas, Louisiana, Pennsylvania, and West Virginia.

Basis of Presentation

The consolidated financial statements included in this Annual Report present the Company s financial position, results of operations and cash flows for the periods presented in accordance with accounting principles generally accepted in the United States (GAAP). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company evaluates subsequent events through the date the financial statements are issued. Certain reclassifications have been made to the prior year financial statements to conform to the 2014 presentation. The effects of the reclassifications were not material to the Company s consolidated financial statements.

Principles of Consolidation

The consolidated financial statements include the accounts of Southwestern and its wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

Revenue Recognition

Natural gas and oil sales. Natural gas and oil sales are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is reasonably assured. The Company uses the entitlement method that requires revenue recognition for the Company s net revenue interest of sales from its properties. Accordingly, natural gas and oil sales are not recognized for deliveries in excess of the Company s net revenue interest, while natural gas and oil sales are recognized for any under delivered volumes. Production imbalances are generally recorded at estimated sales prices of the anticipated future settlements of the imbalances. The Company had no significant production imbalances at December 31, 2014 or 2013.

Marketing. The Company generally markets its natural gas and oil, as well as some products produced by third parties, to brokers, local distribution companies and end-users, pursuant to a variety of contracts. Marketing revenues are recognized when delivery has occurred, title has transferred, the price is fixed or determinable and collectability of the revenue is reasonably assured.

Gas gathering. In certain areas, the Company gathers its natural gas as well as some natural gas produced by third parties pursuant to a variety of contracts. Gas gathering revenues are recognized when the service is performed, the price is fixed or determinable and collectability of the revenue is reasonably assured.

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Cash and Cash Equivalents

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk.

Certain of the Company s cash accounts are zero-balance controlled disbursement accounts that do not have the right of offset against the Company s other cash balances. The Company presents the outstanding checks written against these zero-balance accounts as a component of accounts payable in the accompanying consolidated balance sheets. Outstanding checks included as a component of accounts payable totaled $17 million and $5 million as of December 31, 2014 and 2013, respectively.

Inventory

Inventory is comprised of natural gas in underground storage and tubular and other equipment. Natural gas in underground storage is carried at the lower of cost or market and accounted for by a weighted average cost method. Tubulars and other equipment are carried at the lower of cost or market and are accounted for by a moving weighted average cost method that is applied within specific classes of inventory items.

The components of inventory as of December 31, 2014 and December 31, 2013 consisted of the following:

	For year ended December 31,	
	2014	2013
	(in millions)	
Inventory:		
Natural gas in underground storage	$4	$4
Tubulars and other equipment	33	34

Property, Depreciation, Depletion and Amortization

Natural Gas and Oil Properties. The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil reserves. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country by country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10% plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Companies utilizing the full cost method must use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.35 per MMBtu, West Texas Intermediate oil of $91.48 per barrel and NGLs of $23.79 per barrel, adjusted for market differentials, the Company s net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2014. Cash flow hedges of natural gas production in place increased this ceiling amount by approximately $4 million, net of tax, as of December 31, 2014. At December 31, 2013, the ceiling value of the Company s reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.67 per MMBtu, West Texas Intermediate oil of $93.42 per barrel, and NGLs of $43.45 per barrel. At December 31, 2012, the ceiling value of the Company s reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.76 per MMBtu and for West Texas Intermediate oil of $91.21. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments. During 2012, the net capitalized costs of the Company s natural gas and oil properties exceeded the ceiling by approximately $1,192 million (net of tax) and resulted in a non-cash ceiling test impairment.

All of the Company s costs directly associated with the acquisition and evaluation of properties in Canada relating to its exploration program as of December 31, 2014 and as of December 31, 2013 were unproved and did not exceed the ceiling amount. If the exploration program in Canada is unsuccessful on all or a portion of these properties, including the effects of changes in laws or regulations due to the new government in New Brunswick or otherwise or the Company s exploration licenses in New Brunswick are not renewed in the first quarter of 2015, a ceiling test impairment may result in the future.

Gathering Systems. The Company s investment in gathering systems is primarily related to its Fayetteville Shale assets in Arkansas and Northeast Appalachia assets in Pennsylvania. These assets are being depreciated on a straight-line basis over 25 years.

Capitalized Interest. Interest is capitalized on the cost of unevaluated natural gas and oil properties that are excluded from amortization and actively being evaluated.

Asset Retirement Obligations. The Company owns natural gas and oil properties, which require expenditures to plug and abandon the wells and reclaim the associated pads when reserves in the wells are depleted. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Impairment of long-lived assets. The carrying values of long-lived assets are evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management s estimates of the ultimate outcome of various tax uncertainties. The Company recognizes penalties and interest related to uncertain tax positions within the provision (benefit) for income taxes line in the accompanying Consolidated Statements of Operations. Additional information regarding uncertain tax positions can be found in Note 10 Income Taxes.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage defined commodity price risks and does not use them for speculative trading purposes. The Company uses commodity fixed price swaps and fixed price option contracts to hedge sales of natural gas. Gains and losses resulting from the settlement of hedge contracts have been recognized in gas sales if designated for hedge accounting treatment or gain (loss) on derivatives if not designated for hedge accounting treatment in the consolidated statements of operations when the contracts expire and the related physical transactions of the commodity hedged are recognized. Changes in the fair value of derivative instruments designated as cash flow hedges and not settled are included in other comprehensive income (loss) to the extent that they are effective in offsetting the changes in the cash flows of the hedged item. In contrast, gains and losses from the ineffective portion of fixed price swaps designated for hedge accounting treatment are recognized currently and have an inconsequential impact in the consolidated statement of operations. Gains and losses from the unsettled portion of fixed price swaps not designated for hedge accounting treatment, interest rate swaps, fixed price call options and basis swaps that were not designated for hedge accounting treatment are recognized in gain (loss) on derivatives in the consolidated statement of operations. See Note 5 and Note 7 for a discussion of the Company s hedging activities.

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Earnings Per Share

Basic earnings per common share is computed by dividing net income (loss) attributable to Southwestern by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock. Antidilutive is an increase in earnings per share or reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

For the year ended December 31, 2014, outstanding options for 241,603 shares with an average exercise price of $34.03 were included in the calculation of diluted shares. Options for 1,446,004 shares were excluded from the calculation because they would have had an antidilutive effect. For the year ended December 31, 2013, outstanding options for 377,626 shares with an exercise price of $28.03 were included in the calculation of diluted shares. Options for 1,634,695 shares were excluded from the calculation because they would have had an antidilutive effect. As the Company recognized a net loss for the year ended December 31, 2012, the unvested stock options were not recognized in diluted earnings per share calculations as they would be antidilutive. Options for 1,716,109 shares were excluded from the calculation of diluted shares because they would have had an antidilutive effect.

For the year ended December 31, 2014, 448,415 shares of restricted stock were included in the calculation of diluted shares. The calculation excluded 29,879 shares of restricted stock because they would have had an antidilutive effect. For the year ended December 31, 2013, 258,396 shares of restricted stock were included in the calculation of diluted shares. The calculation excluded 114,433 shares of restricted stock because they would have had an antidilutive effect. As the Company recognized a net loss for the year ended December 31, 2012, the unvested share-based payments were not recognized in diluted earnings per share calculations as they would be antidilutive. The calculation of diluted shares excluded 602,429 shares of restricted because they would have had an antidilutive effect.

For the year ended December 31, 2014, 273,918 shares of performance units were included in the calculation of diluted shares. There were no performance units issued in 2013.

Supplemental Disclosures of Cash Flow Information

The following table provides additional information concerning interest and income taxes paid as well as changes in noncash investing activities for the years ended December 31, 2014, 2013, and 2012.

	For the years ended December 31,		
	2014	2013	2012
	(in millions)		
Cash paid during the year for interest, net of amounts capitalized	$50	$36	$17
Cash paid during the year for income taxes	28	19	1
Increase (decrease) in noncash property additions	174	(13)	(26)

Stock-Based Compensation

The Company accounts for stock-based compensation transactions using a fair value method and recognizes an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalizes the cost into natural gas and oil properties or gathering systems included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of the Company s natural gas and oil properties or directly related to the construction of the Company s gathering systems.

Treasury Stock

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan for certain key employees whereby participants may elect to defer and contribute a portion of their compensation to a Rabbi Trust, as permitted by the plan. The Company includes the assets and liability of its supplemental retirement savings plan in its consolidated balance sheet. Shares of the Company s common stock purchased under the non-qualified deferred compensation arrangement are held in the Rabbi Trust and are presented as treasury stock and carried at cost. As of December 31, 2014, 11,055 shares were accounted for as treasury stock, compared to 9,924 shares at December 31, 2013.

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Foreign Currency Translation

The Company has designated the Canadian dollar as the functional currency for our operations in Canada. The cumulative translation effects of translating the accounts from the functional currency into the U.S. dollar at current exchange rates are included as a separate component of stockholders' equity.

New Accounting Standards Not Yet Implemented in this Report

In April 2014, the FASB issued Accounting Standards Update No. 2014-08 (Update 2014-08), which amends FASB Accounting Standards Codification Topic 205, Presentation of Financial Statements and Topic 360, Property, Plant, and Equipment. Update 2014-08 alters the definition of a discontinued operation to cover only asset disposals that are a strategic shift with a major effect on an entity s operations and finances, and calls for more extensive disclosures about a discontinued operation s assets, liabilities, income and expenses. The guidance is effective for all disposals or classifications as held-for sale of components of an entity that occur within annual periods beginning on or after December 15, 2014. The Company has evaluated the provisions of Update 2014-08 and does not expect it to have an impact on its consolidated results of operations, financial position or cash flows.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (Update 2014-09), which seeks to provide clarity for recognizing revenue. Topic 606 Revenue from Contracts with Customers will supersede the revenue recognition requirement as in Topic 605 Revenue Recognition. Update 2014-09 requires an entity to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to those goods or services. Entities may apply the amendments in Update 2014-09 either (a) retrospectively to each reporting period presented, and the entity may elect a practical expedient per the update, or (b) retrospectively with the cumulative effect of initially applying Update 2014-09 recognized at the date of initial application if an entity elects this transition method it also should provide the additional disclosures in reporting periods. For public entities, Update 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The Company is currently evaluating the provisions of Update 2014-09 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In June 2014, the FASB issued Accounting Standards Update No. 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could be Achieved After the Requisite Service Period (Update 2014-12), which clarifies the accounting treatment of such awards in practice. Update 2014-12 requires that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. Entities may apply the amendments in Update 2014-12 either (a) prospectively to all awards granted or modified after the effective date, or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. Update 2014-12 is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015, and early adoption is permitted. The Company is currently evaluating the provisions of Update 2014-12 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

(2) ACQUISITIONS

On December 22, 2014, the Company completed the acquisition of certain oil and gas assets from a subsidiary of Chesapeake Energy Corporation covering approximately 413,000 net acres in West Virginia and southwest Pennsylvania targeting natural gas, NGLs and crude oil contained in the Upper Devonian, Marcellus and Utica Shales for approximately $5.0 billion, subject to customary closing adjustments (the Chesapeake Property Acquisition). The transaction was temporarily financed using a $4.5 billion 364-day senior unsecured bridge term loan credit facility and a $500 million two-year unsecured term loan. The Company repaid all principal and interest outstanding on the $4.5 billion bridge term loan credit facility on January 23, 2015 after permanent financing was finalized. See Note 16 Subsequent Events for further details.

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The following table summarizes the consideration paid for the Chesapeake Property Acquisition and the fair value of the assets acquired and liabilities assumed as of the acquisition date. The purchase price allocation is preliminary and subject to adjustment. These amounts will be finalized as soon as possible, but no later than one year from the acquisition date.

		For the year ended December 31, 2014
Consideration:		(in millions)
Cash	$	4,978
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Assets acquired:		
Proved natural gas and oil properties		1,424
Unproved natural gas and oil properties		3,605
Other property and equipment		19
Inventory		2
Other receivables		27
Total assets acquired		5,077
Liabilities assumed:		
Asset retirement obligations		(42)
Other long term liabilities		(57)
Total liabilities assumed		(99)
	$	4,978

The Chesapeake Property Acquisition qualified as a business combination, and as such, the Company estimated the fair value of the assets acquired and liabilities assumed as of the December 22, 2014 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as defined in Note 7   Fair Value.

The Company recorded the assets acquired and liabilities assumed in the Chesapeake Property Acquisition at their estimated fair value of approximately $5.0 billion, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. In addition, the Company included $1 million in general and administrative expenses and $5 million in interest expense for fees related to the Chesapeake Property Acquisition on its Consolidated Statement of Operations for the year ended December 31, 2014. The Company included $47 million in other current assets and $1 million in other assets for unamortized fees related to the bridge facility and term loan facility, respectively, for the Chesapeake Property Acquisition on its Consolidated Balance Sheet as of December 31, 2014. In January 2015, the Company repaid in full amounts outstanding on its bridge facility. Therefore, the Company will expense the $47 million of short-term unamortized debt issuance costs associated with the bridge facility in January 2015.

The results of operations of the Chesapeake Property Acquisition have been included in the Company s consolidated financial statements since the December 22, 2014 closing date, including approximately $10 million of total revenue and $2 million of operating income. Summarized below are the consolidated results of operations for the years ended December 31, 2014 and 2013, on an unaudited pro forma basis, as if the acquisition and related financing had occurred on January 1, 2013. The unaudited pro forma financial information was derived from the historical consolidated statement of operations of the Company and the statement of revenues and direct operating expenses for the Chesapeake Property Acquisition properties. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the acquisition and related financing occurred on the basis assumed above, nor is such information indicative of the Company s expected future results of operations.

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	For the year ended December 31,	
	2014	2013
	(in millions)	
	(unaudited)	
Revenues	$4,440	$3,713
Net Income	927	684

In December 2014, a subsidiary of the Company and a subsidiary of Statoil ASA entered into a purchase and sale agreement in which the Company s subsidiary will acquire certain oil and gas assets covering approximately 30,000 acres in West Virginia and southwest Pennsylvania comprising approximately 20% of Statoil s interests in that acreage for approximately $365 million, subject to other customary adjustments (the Statoil Property Acquisition). All of these assets are also assets in which the Company has acquired interests under the Chesapeake Property Acquisition. This transaction closed in January 2015 and was funded with the revolving credit facility. See Note 16 Subsequent Events for details regarding the closing of this transaction.

In December 2014, the Company announced that it had signed an agreement to purchase oil and gas assets including approximately 46,700 net acres in northeast Pennsylvania from WPX Energy, Inc. for approximately $300 million, subject to customary closing conditions (the WPX Property Acquisition). This acreage was producing approximately 50 million net cubic feet of gas per day from 63 operated horizontal wells as of December 2014. As part of this transaction, the Company will assume firm transportation capacity of 260 million cubic feet of gas per day predominantly on the Millennium pipeline effective upon closing. This transaction closed in January 2015 and was funded with the revolving credit facility. See Note 16 Subsequent Events for details regarding the closing of this transaction.

In March 2014 and July 2014, the Company entered into several agreements to purchase approximately 380,000 net acres in northwest Colorado principally in the Niobrara formation for approximately $215 million. The Company utilized its revolving credit facility to finance these acquisitions. The Company closed the acquisitions in the second and third quarters and accounted for them as asset acquisitions.

In April 2013, the Company entered into a definitive purchase agreement to acquire natural gas properties located in Pennsylvania prospective for the Marcellus Shale for approximately $82 million, subject to closing conditions. The Company utilized its revolving credit facility to finance the acquisition. The Company closed the acquisition during the second quarter of 2013 and accounted for it as an asset acquisition.

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(3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of December 31, 2014 and December 31, 2013 consisted of the following:

	2014	2013
	(in millions)	
Deposits (1)	$65	$
Prepaid taxes	18	14
Prepaid insurance	8	8
Prepaid drilling costs	1	9
Total	$92	$31

(1) Deposits consist of a $50 million and $15 million pre-payment related to the Statoil Property Acquisition and WPX Property Acquisition, respectively.

(4) NATURAL GAS AND OIL PRODUCING ACTIVITIES (UNAUDITED)

The Company s natural gas and oil properties are located in the United States and Canada.

Net Capitalized Costs

The following table shows the capitalized costs of natural gas and oil properties and the related accumulated depreciation, depletion and amortization as of December 31, 2014 and 2013:

	2014		2013	
	(in millions)			
Proved properties	$15,860		$12,337	
Unproved properties	4,646	(1)	957	(1)
Total capitalized costs	20,506	(2)	13,294	
Less: Accumulated depreciation, depletion and amortization	8,327		7,481	
Net capitalized costs	$12,179		$5,813	

(1) Includes $76 million and $72 million related to the Company s exploration program in Canada as of December 31, 2014 and 2013, respectively.
(2) Includes approximately $5.0 billion related to the Chesapeake Property Acquisition.

Natural gas and oil properties not subject to amortization represent investments in unproved properties and major development projects in which the Company owns an interest. These unproved property costs include unevaluated costs associated with leasehold or drilling interests and unevaluated costs associated with wells in progress. The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2014.

	2014	2013	2012	Prior	Total	
	(in millions)					
Property acquisition costs	$3,892	$87	$75	$142	$4,196	(1)
Exploration and development costs	239	40	26	61	366	(1)
Capitalized interest	13	10	14	47	84	(1)
	$4,144	$137	$115	$250	$4,646	

(1) Property acquisition costs include $36 million, exploration costs include $31 million and capitalized interest includes $9 million related to the Company s exploration program in Canada.

Of the total net unevaluated costs excluded from amortization as of December 31, 2014, approximately $3.6 billion is related to the Chesapeake Property Acquistion, approximately $12 million is related to unevaluated seismic costs in the Fayetteville Shale, approximately $34 million is related to the acquisition of undeveloped properties in the Company s Fayetteville Shale, approximately $138 million is related to the acquisition of undeveloped properties in the Company s Marcellus Shale and approximately $367 million is related to the acquisition of undeveloped properties in the Company s New Ventures, excluding its exploration program in Canada. The Company has $76 million of unevaluated costs related to

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its exploration program in Canada. Additionally, the Company has approximately $267 million of unevaluated costs related to costs of wells in progress. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The timing and amount of property acquisition and seismic costs included in the amortization computation will depend on the location and timing of drilling wells, results of drilling, and other assessments. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

Costs Incurred in Natural Gas and Oil Exploration and Development

The table below sets forth capitalized costs incurred in natural gas and oil property acquisition, exploration and development activities:

	2014	2013	2012
	(in millions, except per Mcfe amounts)		
Proved property acquisition costs	$1,455	$1	$
Unproved property acquisition costs (1)	3,934	168	221
Exploration costs(2)	232	192	197
Development costs	1,600	1,662	1,493
Capitalized costs incurred	7,221	2,023	1,911
Full cost pool amortization per Mcfe	$1.10	$1.08	$1.31

(1) Includes $1 million, $17 million and $4 million, in 2014, 2013 and 2012, respectively, related to the Company s exploration program in Canada.
(2) Includes $3 million, $12 million and $3 million in 2014, 2013 and 2012, respectively, related to the Company s exploration program in Canada.

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $55 million, $62 million and $62 million during 2014, 2013 and 2012, respectively, based on the Company s weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling $320 million, $264 million and $237 million during 2014, 2013 and 2012, respectively, that were directly related to the acquisition, exploration and development of the Company s natural gas and oil properties. Included in these amounts are internal costs from the Company s subsidiaries involved with vertical integration of the Company s exploration and development activities and totaled $123 million, $103 million and $82 million during 2014, 2013 and 2012, respectively. All internal costs are included in the Company s cost of natural gas and oil properties.

Results of Operations from Natural Gas and Oil Producing Activities

The table below sets forth the results of operations from natural gas and oil producing activities:

	2014	2013	2012
	(in millions)		
Sales	$2,862	$2,404	$1,963
Production (lifting) costs	(776)	(629)	(505)
Depreciation, depletion and amortization	(884)	(735)	(765)
Impairment of natural gas and oil properties			(1,940)
	1,202	1,040	(1,247)

Provision (benefit) for income taxes	457	416	(497)
Results of operations (1)	$745	$624	$(750)

(1) Results of operations exclude the mark-to-market gain or loss on commodity derivative instruments. See Note 5 Derivatives and Risk Management.

The results of operations shown above exclude general and administrative expenses and interest expense and are not necessarily indicative of the contribution made by the Company s natural gas and oil operations to its consolidated operating results. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

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Natural Gas and Oil Reserve Quantities

The Company engaged the services of Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm, to audit the reserves estimated by the Company s reservoir engineers. In conducting its audit, the engineers and geologists of NSAI studied the Company s major properties in detail and independently developed reserve estimates. NSAI s audit consists primarily of substantive testing, which includes a detailed review of the Company s major properties and accounted for approximately 97%, 95% and 93% of the present worth of the Company s total proved reserves as of December 31, 2014, 2013 and 2012, respectively. A reserve audit is not the same as a financial audit and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimate of reserves. Reserve estimates are inherently imprecise and the Company s reserve estimates are generally based upon extrapolation of historical production trends, historical prices of natural gas and crude oil and analogy to similar properties and volumetric calculations. Accordingly, the Company s estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available. For more information over reserves, refer to the table titled Changes in Proved Undeveloped Reserves (Bcfe) in Business Exploration and Production in Item 1 of this Annual Report.

The following table summarizes the changes in the Company s proved natural gas, NGLs and oil reserves for 2014, 2013 and 2012 all of which were located in the United States:

	2014			2013			2012		
	Natural Gas (Bcf)	Oil (MBbls)	NGL (MBbls)	Natural Gas (Bcf)	Oil (MBbls)	NGL (MBbls)	Natural Gas (Bcf)	Oil (MBbls)	NGL (MBbls)
Proved reserves, beginning of year	6,974	373		4,017	244		5,887	996	
Revisions of previous estimates	542	(14)	66	325	38	50	(2,088)	(44)	
Extensions, discoveries and other additions	1,691	250	48	3,283	229		918	154	
Production	(765)	(235)	(231)	(655)	(138)	(50)	(564)	(83)	
Acquisition of reserves in place	1,367	37,246	118,816	4					
Disposition of reserves in place		(5)					(136)	(779)	
Proved reserves, end of year	9,809	37,615	118,699	6,974	373		4,017	244	
Proved developed reserves:									
Beginning of year	4,237	372		3,196	243		3,254	983	
End of year	5,675	7,445	38,632	4,237	372		3,196	243	
Proved undeveloped reserves:									
Beginning of year	2,737	1		821	1		2,633	13	
End of year	4,134	30,170	80,067	2,737	1		821	1	

The Company s estimated proved natural gas and oil reserves were 10,747 Bcfe at year-end 2014, compared to 6,976 Bcfe at year-end 2013. The significant increase in the Company s reserves in 2014 was primarily due to the acquisition of approximately 413,000 net acres in Southwest Appalachia, successful development drilling programs in the Fayetteville Shale and Northeast Appalachia and upward performance revisions in Northeast Appalachia. In 2014, the Company s production was 768 Bcfe, up from 657 Bcfe in 2013. The increase in production in 2014 resulted primarily from a 103 Bcf increase in net production from the Company s Northeast Appalachia properties, a 3 Bcfe increase in net production from its Southwest Appalachia properties, and an 8 Bcf increase in net production from its Fayetteville Shale properties, which more than offset a combined 3 Bcfe decrease in net production from its East Texas and

Arkoma Basin properties. The Company replaced 591% of its production volumes with 1,693 Bcfe of proved reserve additions, net upward revisions of 543 Bcfe, and 2,304 Bcfe of proved reserve additions as a result of acquisitions primarily associated with acreage in Southwest Appalachia. Of the reserve additions, 283 Bcfe, 246 Bcfe and 2 Bcfe from the Company s Fayetteville Shale, Northeast Appalachia, and Brown Dense divisions, respectively, were proved developed and 573 Bcfe and 589 Bcfe from its Fayetteville Shale and Northeast Appalachia divisions, respectively, were proved undeveloped. In 2014, upward reserve revisions resulting from higher gas prices totaled 38 Bcf, 10 Bcf and 6 Bcf in the Company s Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. The Company also had performance revisions in 2014 of (126) Bcf, 636 Bcf and (21) Bcf in its Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. The Company s December 31, 2014 proved reserves include 181 Bcfe of proved undeveloped reserves from 60 locations that

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have a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties have a negative present value of $28 million when discounted at 10%. The Company has made a final investment decision and is committed to developing these reserves.

The Company s estimated proved natural gas and oil reserves were 6,976 Bcfe at year-end 2013, compared to 4,018 Bcfe at year-end 2012. The significant increase in the Company s reserves in 2013 was primarily due to its successful development drilling programs in the Fayetteville Shale and Northeast Appalachia and the higher natural gas price environment compared to 2012. In 2013, the Company s production was 657 Bcfe, up from 565 Bcfe in 2012. The increase in production in 2013 resulted primarily from a 97 Bcf increase in net production from the Company s Northeast Appalachia properties, a 1 Bcfe increase in net production from its New Ventures properties, and a 1 Bcf increase in net production from its Fayetteville Shale properties, which more than offset a combined 7 Bcfe decrease in net production from its East Texas and Arkoma Basin properties. The Company replaced 550% of its production volumes with 3,285 Bcfe of proved reserve additions, net upward revisions of 326 Bcfe, and 4 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 557 Bcfe, 386 Bcfe and 2 Bcfe from the Company s Fayetteville Shale, Northeast Appalachia and Brown Dense divisions, respectively, were proved developed and 1,530 Bcfe and 810 Bcfe from its Fayetteville Shale and Northeast Appalachia divisions, respectively, were proved undeveloped. In 2013, upward reserve revisions resulting from higher gas prices totaled 191 Bcf, 35 Bcf and 21 Bcf in the Fayetteville Shale, Northeast Appalachia, and the Company s Ark-La-Tex division, respectively. The Company also had upward performance revisions in 2013 of 16 Bcf, 62 Bcf and 1 Bcf in the Fayetteville Shale, Northeast Appalachia, and the Company s New Ventures division, respectively. Additionally, the Company s reserves increased by 4 Bcf in 2013 as a result of the acquisition of natural gas leases and wells in Northeast Appalachia. The Company s December 31, 2013 proved reserves include 662 Bcfe of proved undeveloped reserves from 268 locations that have a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties have a negative present value of $97 million when discounted when at 10%.

The Company s estimated proved natural gas and oil reserves were 4,018 Bcfe at year-end 2012, compared to 5,893 Bcfe at year-end 2011. The overall decrease in total estimated proved reserves in 2012 was primarily due to the low natural gas price environment. In 2012, the Company s production was 565 Bcfe, up from 500 Bcfe in 2011. The increase in production in 2012 resulted primarily from a 49 Bcf increase in production from the Fayetteville Shale and a 30 Bcf increase in the Company s Northeast Appalachia production, which more than offset a combined 14 Bcfe decrease in net production from the Company s East Texas and Arkoma Basin properties. The Company replaced its production volumes with 920 Bcfe of proved reserve additions as a result of its drilling and acquisition program but also incurred net downward revisions of 2,088 Bcfe principally due to a decrease in the price of natural gas and to a lesser extent due to downward performance revisions of 336 Bcfe. Of the reserve additions, 383 Bcfe, 195 Bcfe, 3 Bcfe and 2 Bcfe from the Company s Fayetteville Shale, Northeast Appalachia, Ark-La-Tex, and New Ventures divisions, respectively, were proved developed and 32 Bcfe and 305 Bcfe from its Fayetteville Shale and Northeast Appalachia divisions, respectively, were proved undeveloped. The total downward reserve revisions were primarily impacted by the low commodity price environment in 2012 and to a lesser extent by downward performance revisions. In 2012, downward reserve revisions resulting from lower gas prices totaled 1,684 Bcf, 9 Bcf and 59 Bcf in the Fayetteville Shale, Northeast Appalachia, and the Company s Ark-La-Tex division, respectively. The Company also had a net downward performance revision in 2012 of 362 Bcf and 10 Bcf in the Fayetteville Shale and its Ark-La-Tex division, respectively. The Company had a net positive performance revision in 2012 of 36 Bcf in Northeast Appalachia. Additionally, the Company s reserves decreased by 141 Bcf in 2012 as a result of its disposition of natural gas leases and wells in the Overton Field in East Texas. The Company s December 31, 2012 proved reserves include 355 Bcfe of proved undeveloped reserves from 198 locations that have a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties have a negative present value of $71 million when discounted when at 10%.

The Company has no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. The Company used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

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Standardized Measure of Discounted Future Net Cash Flows

The following standardized measures of discounted future net cash flows relating to proved natural gas and oil reserves as of December 31, 2014, 2013 and 2012 are calculated after income taxes and discounted using a 10% annual discount rate and do not purport to present the fair market value the Company s proved gas and oil reserves:

	2014	2013	2012
	(in millions)		
Future cash inflows	$41,812	$22,624	$9,570
Future production costs	(16,477)	(8,896)	(4,737)
Future development costs	(5,750)	(3,626)	(711)
Future income tax expense	(4,743)	(3,223)	(745)
Future net cash flows	14,842	6,879	3,377
10% annual discount for estimated timing of cash flows	(7,299)	(3,143)	(1,326)
Standardized measure of discounted future net cash flows	$7,543	$3,736	$2,051

Under the standardized measure, future cash inflows were estimated by applying an average price from the first day of each month from the previous 12 months, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Prices used for the standardized measure above were $4.35 per MMBtu for natural gas, $91.48 per barrel for oil and $23.79 per barrel for NGLs in 2014, $3.67 per MMBtu for natural gas, $93.42 per barrel for oil and $43.45 per barrel for NGLs in 2013, and $2.76 per MMBtu for natural gas and $91.21 per barrel for oil in 2012. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the year-end statutory rate to the excess of pre-tax cash inflows over the Company s tax basis in the associated proved gas and oil properties after giving effect to permanent differences and tax credits.

Following is an analysis of changes in the standardized measure during 2014, 2013 and 2012:

	2014	2013	2012
	(in millions)		
Standardized measure, beginning of year	$3,736	$2,051	$3,451
Sales and transfers of natural gas and oil produced, net of production costs	(2,084)	(1,774)	(1,444)
Net changes in prices and production costs	1,192	1,853	(2,605)
Extensions, discoveries, and other additions, net of future production and development costs	1,049	1,454	550
Acquisition of reserves in place	1,897	5	
Sales of reserves in place			(157)
Revisions of previous quantity estimates	622	349	(1,109)
Accretion of discount	513	232	480
Net change in income taxes	(522)	(1,120)	1,079
Changes in estimated future development costs	110	(196)	2,476
Previously estimated development costs incurred during the year	815	223	62
Changes in production rates (timing) and other	215	659	(732)
Standardized measure, end of year	$7,543	$3,736	$2,051

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(5) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas and oil which impacts the predictability of its cash flows related to the sale of natural gas, NGLs and oil. These risks are managed by the Company s use of certain derivative financial instruments. As of December 31, 2014 and 2013, the Company s derivative financial instruments consisted of fixed price swaps, basis swaps, fixed price call options, and interest rate swaps. A description of the Company s derivative financial instruments is provided below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty.
Basis swaps	Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
Fixed price call options	The Company sells fixed price call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty such excess on sold fixed price call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
Interest rate swaps	Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company s existing or anticipated exposure to unfavorable interest rate changes.

All derivatives are recognized in the balance sheet as either an asset or liability and are measured at fair value other than transactions for which normal purchase/normal sale is applied. Certain criteria must be satisfied in order for derivative financial instruments to be classified and accounted for as either a cash flow or a fair value hedge. Accounting for qualifying hedges requires a derivative s gains and losses to be recorded either in earnings or as a component of other comprehensive income. Gains and losses on derivatives that are not designated for hedge accounting treatment or that do not meet hedge accounting requirements are recorded in earnings as a component of gain (loss) on derivatives. Within the gain (loss) on derivatives component of the statement of operations are gains (losses) on derivatives excluding derivatives, settled and gains (losses) on derivatives, settled. The Company calculates gains (losses) on derivatives, settled, as the summation of gains and losses on positions which have settled within the period.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy at the time the transactions are entered into and the Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the events in the financial markets in recent years demonstrate there can be no assurance that a counterparty will be able to meet its obligations to the Company.

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The balance sheet classification of the assets related to derivative financial instruments are summarized below as of December 31, 2014 and 2013:

	Derivative Assets December 31, 2014 Balance Sheet Classification (in millions)	Fair Value	December 31, 2013 Balance Sheet Classification	Fair Value
Derivatives designated as hedging instruments:				
Fixed price swaps	Derivative assets	$ 165	Derivative assets	$ 21
Total derivatives designated as hedging instruments		$ 165		$ 21
Derivatives not designated as hedging instruments:				
Basis swaps	Derivative assets	$ 9	Derivative assets	$ 13
Fixed price swaps	Derivative assets	163	Derivative assets	37
Basis swaps	Other long-term assets	1	Other long-term assets	
Interest rate swaps	Other long-term assets	1	Other long-term assets	8
Total derivatives not designated as hedging instruments		$ 174		$ 58
Total derivative assets		$ 339		$ 79

	Derivative Liabilities December 31, 2014 Balance Sheet Classification (in millions)	Fair Value	December 31, 2013 Balance Sheet Classification	Fair Value
Derivatives designated as hedging instruments:				
Fixed price swaps	Derivative liabilities	$	Derivative liabilities	$ 4
Total derivatives designated as hedging instruments		$		$ 4
Derivatives not designated as hedging instruments:				
Basis swaps	Derivative liabilities	$ 4	Derivative liabilities	$ 1
Fixed price call options	Derivative liabilities	2	Derivative liabilities	
Interest rate swaps	Derivative liabilities	3	Derivative liabilities	2
Fixed price call options	Other long-term liabilities	10		31

Basis swaps	Other long-term liabilities	2	Other long-term liabilities Other long-term liabilities	
Interest rate swaps	Other long-term liabilities	2	Other long-term liabilities	3
Total derivatives not designated as hedging instruments		$ 23		$ 37
Total derivative liabilities		$ 23		$ 41

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As of December 31, 2014, the Company had fixed price swap derivatives designated for hedge accounting and not designated for hedge accounting on the following volumes of natural gas production (in Bcf):

Year	Fixed price swaps designated for hedge accounting	Fixed price swaps not designated for hedge accounting	Total	Weighted Average Price to be Swapped ($/MMBtu) (1)
2015	120	120	240	$4.40

(1) The weighted average price to be swapped is $4.40 for each category and in total.

Cash Flow Hedges

The reporting of gains and losses on cash flow derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gains and losses on the derivative hedging instruments are recorded in other comprehensive income until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from the derivative hedging instrument are recognized in earnings immediately and had an inconsequential impact to the consolidated statement of operations as of December 31, 2014 and 2013.

As of December 31, 2014, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $98 million net of a deferred income tax liability of $65 million. The amount recorded in accumulated other comprehensive income will be relieved over time and recognized in the statement of operations as the physical transactions being hedged occur. Assuming the market prices of natural gas futures as of December 31, 2014 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $98 million from accumulated other comprehensive income to earnings during the next 12 months. Gains or losses from derivative instruments designated as cash flow hedges are reflected as adjustments to natural gas sales in the consolidated statements of operations. Volatility in net income, comprehensive income and accumulated other comprehensive income may occur in the future as a result of the Company s derivative activities.

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The following tables summarize the before tax effect of all cash flow hedges on the consolidated financial statements for the years ended December 31, 2014 and 2013.

Derivative Instrument	Gain Recognized in Other Comprehensive Income (Effective Portion) For the years ended December 31, 2014	2013
	(in millions)	
Fixed price swaps	$ 122	$ 38

Derivative Instrument	Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion) For the years ended December 31, 2014	2013
		(in millions)	
Fixed price swaps	Gas Sales	$ (26)	$ 309

Other Derivative Contracts

For other derivative contracts, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately through gain (loss) on derivatives. Although the Company s basis swaps meet the objective of managing commodity price exposure, these trades are typically not entered into concurrent with the Company s derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting. Basis swap derivative instruments that are not designated for hedge accounting are recorded on the balance sheet at their fair values under derivative assets, other long-term assets, other current liabilities, and other long-term liabilities, as applicable and all gains and losses related to these contracts are recognized immediately in the consolidated statements of operations as a component of gain (loss) on derivatives. As of December 31, 2014, the Company had basis swaps on natural gas production that were not designated for hedge accounting of 22 Bcf for 2015 and 4 Bcf for 2016.

As of December 31, 2014, the Company had fixed price call options on 200 Bcf and 120 Bcf of natural gas production in 2015 and 2016, respectively, not designated for hedge accounting and fixed price swaps of 120 Bcf of natural gas production in 2015 not designated for hedge accounting.

The Company is a party to interest rate swaps that were entered into in order to mitigate the Company s exposure to volatility in interest rates. The interest rate swaps build to a notional amount of $170 million and expire on June 20, 2020. The Company did not designate the interest rate swaps for hedge accounting. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives in the consolidated statements of operations.

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The following tables summarize the before tax effect of fixed price swaps, basis swaps, fixed price call options and interest rate swaps not designated for hedge accounting on the condensed consolidated statements of operations for the years ended December 31, 2014 and 2013.

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Net of Settlement	Gain (Loss) on Derivatives, Excluding Derivatives, Settled Recognized in Earnings For the years ended December 31, 2014	2013
		(in millions)	
Basis swaps	Gain (Loss) on Derivatives	$(7)	$7
Fixed price call options	Gain (Loss) on Derivatives	18	(26)
Fixed price swaps	Gain (Loss) on Derivatives	126	37
Interest rate swaps	Gain (Loss) on Derivatives	(7)	3

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled (1)	Gain (Loss) on Derivatives, Settled (1) Recognized in Earnings For the years ended December 31, 2014	2013
		(in millions)	
Basis swaps	Gain (Loss) on Derivatives	$12	$5
Fixed price swaps	Gain (Loss) on Derivatives	(2)	
Interest rate swaps	Gain (Loss) on Derivatives	(1)	

(1) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.

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(6) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME

The following tables detail the components of accumulated other comprehensive income (loss) and the related tax effects for the year ended December 31, 2014:

	For the year ended December 31, 2014 Gains (Losses) on Cash Flow Hedges	Pension and Other Postretirement	Foreign Currency	Total
	(in millions) (1)			
Beginning balance, December 31, 2013	$9	$ (9)	$ (4)	$ (4)
Other comprehensive income (loss) before reclassifications	73		(8)	65
Amounts reclassified from/to other comprehensive income (2)	16	(15)		1
Net current-period other comprehensive income (loss)	89	(15)	(8)	66
Ending balance, December 31, 2014	$98	$ (24)	$ (12)	$ 62

(1) All amounts are net of tax.
(2) See separate table below for details about these reclassifications.

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from/to Accumulated Other Comprehensive Income For the year ended December 31, 2014 (in millions)
Gains (losses) to Other Comprehensive Income on cash flow hedges		
Settlements	Gas sales	$26
Ineffectiveness	Gas sales	
	Gain before income taxes	26
	Less: Provision for income taxes	10
	Net Gain	$16
Pension and other postretirement (1)		
Net actuarial loss(2)		$(25)
	Loss before income taxes	(25)
	Less: Benefit for income taxes	(10)
	Net Loss	$(15)
Total reclassifications for the period	Net Gain	$1

(1) See Note 12 for additional details regarding the Company s retirement and employee benefit plans.

(2) Net actuarial loss had no impact on the consolidated statement of operations.

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(7) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company s financial instruments as of December 31, 2014 and 2013 were as follows:

	December 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Cash and cash equivalents	$53	$53	$23	$23
Credit facility	$300	$300	$283	$283
Term loan facility	$500	$500	$	$
Bridge facility	$4,500	$4,500	$	$
Senior notes	$1,667	$1,751	$1,668	$1,796
Derivative instruments, net	$316	$316	$38	$38

The carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities on the consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company s senior notes were based on the market for the Company s publicly-traded debt as determined based on yield of the Company s 7.5% Senior Notes due 2018, which was 3.2% as of December 31, 2014 and 2.6% at December 31, 2013, and its 4.10% Senior Notes due 2022, which was 4.3% as of December 31, 2014 and 4.2% at December 31, 2013. The carrying values of the borrowings under the Company s unsecured revolving credit facility, bridge facility, and term loan facility approximate fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its debt to be a Level 2 measurement on the fair value hierarchy.

Derivative Instruments: The fair value of all derivative instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

The fair value hierarchy prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations -	Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.
Level 2 valuations -	Consist of quoted market information for the calculation of fair market value.
Level 3 valuations -	Consist of internal estimates and have the lowest priority.

The Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company s Level 2 fair value measurements include fixed price swaps and are estimated using internal discounted cash flow calculations using the NYMEX futures index. The Company utilized discounted cash flow models for valuing its interest rate derivatives. The net derivative values attributable to the Company s interest rate derivative contracts as of December 31, 2014 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate (LIBOR) yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company s interest rate derivative asset and liability measurement represent Level 2 inputs in the hierarchy. The Company s Level 3 fair value measurements include fixed price call options and basis swaps. The Company s fixed price call options are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company s basis swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves.

Inputs to the Black-Scholes model, including the volatility input, which is the significant unobservable input for Level 3 fair value measurements, are obtained from a third-party pricing source, with independent verification of most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively. However, such changes would not have a significant impact.

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Assets and liabilities measured at fair value on a recurring basis are summarized below (in millions):

	December 31, 2014			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Derivative assets	$	$ 329	$ 10	$ 339
Derivative liabilities		(5)	(18)	(23)
Total	$	$ 324	$ (8)	$ 316

	December 31, 2013			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Derivative assets	$	$ 66	$ 13	$ 79
Derivative liabilities		(9)	(32)	(41)
Total	$	$ 57	$ (19)	$ 38

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2014 and 2013. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company s judgment, reflect reasonable assumptions a marketplace participant would have used as of December 31, 2014 and December 31, 2013.

	For the years ended December 31,	
	2014	2013
	(in millions)	
Balance at beginning of period	$(19)	$

Total gains (losses):		
Included in earnings	23	(14)
Included in other comprehensive income		
Purchases, issuances, and settlements:		
Purchases		
Issuances		
Settlements	(12)	(5)
Transfers into/out of Level 3		
Balance at end of period	$(8)	$(19)
Change in gains (losses) included in earnings relating to derivatives still held as of December 31	$11	$(19)

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(8) DEBT

The components of debt as of December 31, 2014 and 2013 consisted of the following:

	2014	2013
	(in millions)	
Short-term debt:		
7.15% Senior Notes due 2018	$1	$1
Variable rate (1.515% at December 31, 2014) bridge facility, due December 2015	4,500	
Total short-term debt	4,501	1
Long-term debt:		
Variable rate (1.515% and 1.640% at December 31, 2014 and December 31, 2013, respectively) credit facility, expires December 2018	300	283
Variable rate (1.545% at December 31, 2014) term loan facility, due December 2016	500	
7.35% Senior Notes due 2017	15	15
7.125% Senior Notes due 2017	25	25
7.15% Senior Notes due 2018	27	28
7.5% Senior Notes due 2018	600	600
4.10% Senior Notes due 2022	1,000	1,000
Unamortized discount	(1)	(1)
Total long-term debt	2,466	1,950
Total debt	$6,967	$1,951

The following is a summary of scheduled long-term debt maturities by year as of December 31, 2014 (in millions):

2016	501
2017	41
2018	925
Thereafter	1,000
	$2,467

Chesapeake Property Acquisition Financing

On December 19, 2014, the Company entered into a $4.5 billion unsecured 364-day bridge term loan credit agreement with various lenders. The bridge facility requires prepayments under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business or for specified uses. The Company repaid the $4.5 billion outstanding and terminated the bridge facility in January 2015 with net proceeds of $669 million and $1.7 billion from common stock and depositary share offerings, respectively, and $2.2 billion from senior note offerings with the difference utilized to pay down amounts under the revolving credit facility.

On December 19, 2014, the Company also entered into a $500 million unsecured two-year term loan credit agreement with various lenders. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business.

Credit, Bridge and Term Facilities

The Company s revolving credit facility provides a borrowing capacity of up to $2.0 billion and matures on December 2018, with options for two one-year extensions with participating lender approval. The amount available under the revolving credit facility may be increased by $500 million upon the Company s agreement with its participating lenders. The interest rates on the revolving credit facility, bridge facility and term loan facility are calculated based upon the Company s credit rating and were 137.5 basis points over the current London Interbank Offered Rate, or LIBOR as of December 31, 2014, and is currently at 150 basis points over the current LIBOR. The interest rate on the revolving credit facility at December 31, 2013 was 150 basis points over LIBOR. The revolving credit facility, bridge facility and term

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loan facility are unsecured and are not guaranteed by any subsidiaries of the Company. The revolving credit facility, bridge facility and term loan facility contain covenants which impose certain restrictions on us, including a financial covenant under which the Company may not issue total debt in excess of 60% of its total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments (after December 31, 2011), certain hedging activities and the Company s pension and other postretirement liabilities. As of December 31, 2014, the Company was in compliance with the covenants of its revolving credit facility, bridge facility, term loan facility and other debt agreements.

(9) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

The Company has commitments to third parties for demand transportation charges. As of December 31, 2014, future payments under non-cancelable firm transportation charges are approximately $478 million in 2015, $515 million in 2016, $543 million in 2017, $549 million in 2018, $502 million in 2019 and $2,802 million thereafter.

The Company has 11 leases for pressure pumping equipment for its E&P operations under leases that expire between December 2017 and January 2018. The Company s current aggregate annual payment under the leases is approximately $8 million. The Company has 7 leases for drilling rigs for its E&P operations that expire in 2020. The Company s current aggregate payment under the leases is approximately $13 million. The lease payments for the pressure pumping equipment, as well as other operating expenses for the Company s drilling operations, are capitalized to natural gas and oil properties and are partially offset by billings to third-party working interest owners for their share of fracture stage charges.

The Company leases compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2027. As of December 31, 2014, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $73 million in 2015, $62 million in 2016, $45 million in 2017, $25 million in 2018, $21 million in 2019 and $45 million thereafter. The Company also has commitments for compression services related to its Midstream Services and E&P segments. As of December 31, 2014, future minimum payments under these non-cancelable agreements are approximately $41 million in 2015, $28 million in 2016, $19 million in 2017, $10 million in 2018, and $4 million in 2019.

In response to its well performance, the Company entered into new and amended natural gas transportation and gathering arrangements with third party pipelines during the second quarter of 2013 in support of its production in Northeast Appalachia. As of December 31, 2014, the Company s obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $5.4 billion and it has guarantee obligations of up to $173 million of that amount.

In 2013, the Company started construction on a corporate office complex located in Spring, Texas on 26 acres of commercial land that it purchased in 2012. The Company financed the construction of this complex through a construction agreement and lease arrangement. As of December 31, 2014, the Company was obligated for the construction costs incurred, which approximated $137 million. In January 2015, construction on the corporate campus was completed and the Company commenced a lease with a term of approximately five years.

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately $47 million Canadian dollars in the aggregate over the license periods. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $45 million Canadian dollars. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of December 31, 2014 has invested $45 million Canadian dollars, or $44 million USD, in New Brunswick towards the Company s commitment, fully covering the promissory notes held by the Province of New Brunswick. No liability has been recognized in connection with the promissory notes due to the Company s investments in New Brunswick as of December 31, 2014 and its future investment plans. Our licenses are scheduled to expire in March 2015. The newly elected provincial government in New Brunswick has announced an intent to impose a moratorium on hydraulic fracturing until a list of conditions is met and has introduced authorizing legislation in the provincial legislature. The Company has applied for an extension of its licenses past the end of the moratorium, but as of this time that extension has not been granted. The list of conditions that the provincial government has announced is subjective, and the Company cannot predict the duration of the moratorium or whether it will be granted the extension requested or any other extension. Unless and until the moratorium is lifted and the Company s licenses are extended, it will not be able to continue with its program in New Brunswick. If this extension is not granted, the Company may be required to write off its investment.

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Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or results of operations of the Company.

Litigation

Tovah Energy

In February 2009, one of the Company s subsidiaries was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et al., pending in the 273rd District Court in Shelby County, Texas. By the time of trial in December 2010, Ms. Berry-Helfand (the only remaining plaintiff) alleged that, in 2005, she provided the Company s subsidiary with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that the Company s subsidiary refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, she alleged various statutory and common law claims, including, but not limited to, claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by the Company s subsidiary between February 2005 and February 2006. She also sought disgorgement of the Company s subsidiary s profits. A former associate of the plaintiff intervened in the matter claiming to have helped develop the prospect years earlier.

The jury found in favor of the plaintiff and the intervenor with respect to all of the statutory and common law claims and awarded $11 million in compensatory damages but no special, punitive or other damages. Separately, the jury determined that the Company s subsidiary s profits for purposes of disgorgement, if ordered as a remedy, were $382 million. (Disgorgement of profits is an equitable remedy determined by the judge, and it is within the judge s discretion to award none, some or all of unlawfully obtained profits.) In August 2011, a judgment was entered pursuant to which the plaintiff and the intervenor were entitled to recover approximately $11 million in actual damages and approximately $24 million in disgorgement as well as prejudgment interest and attorneys fees, which currently are estimated to be up to $9 million, and all costs of court of the plaintiff and intervenor.

Both sides appealed and in July 2013, the Tyler Court of Appeals ordered that (1) the judgment awarding the plaintiff and the intervenor $24 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11 million for actual damages, insofar as it is based on the jury s findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret is reversed and judgment rendered that the plaintiff and the intervenor take nothing under those theories of recovery, (3) the award of $11 million to the plaintiff and the intervenor as damages for misappropriation of trade secret is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney s fees for the Company s subsidiary as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. All parties petitioned for rehearing. The Tyler Court of Appeals denied rehearing in November 2013.

The Company s subsidiary filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor filed cross petition for review in April 2014, but conditioned their filing on the courts granting the Company s subsidiary petition for review; i.e., if the court denies the Company s subsidiary s petition for review, then the plantiff and the intervenor are not seeking further review of the court of appeals judgment. On October 24, 2014, the Supreme Court requested full briefing on the merits of the case. Based on the Company s understanding and judgment of the facts and merits of this case, including appellate matters, and after considering the advice of counsel, the Company has determined that, although reasonably possible, a materially adverse final outcome to this action is not probable. As such, the Company has not accrued any amounts with respect to this action. If the Supreme Court declines to rule on the case or affirms all aspects of the court of appeals judgment then the Company s subsidiary would owe the $11 million in damages, plus interest and attorneys fees, offset by any award of attorneys fees for its prevailing on the theft count. The Company s assessment may change in the future due to occurrence of certain events, such as the result of the petitions for review at the Supreme Court of Texas, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the Company s results of operations, financial position or cash flows.

Arkansas Royalty Litigation

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The Company is a defendant in three cases, two filed in Arkansas state court in 2010 and 2013 and one in federal court in 2014, on behalf of putative classes of royalty owners on some of its leases located in Arkansas. The chief complaint in all three cases is that the Company underpaid the royalty owners by, among other things, deducting from royalty payments costs for gathering, transportation, and compression of natural gas in excess of what is permitted by the relevant leases. The Company removed the two cases filed in state court to federal court, but both were remanded to state court during the third quarter of 2014; the appeal of those remand orders is ongoing. Despite the ongoing appeal of the remand, in September and October 2014 the judges in the two Arkansas state actions entered orders certifying classes of royalty owners who are citizens of Arkansas. The Company is appealing those orders. Discovery regarding the plantiffs theories of liability and amount of claimed damages is in the very early stages. Management believes that the deductions from royalty payments as calculated are permitted and intends to defend the cases vigorously. The Company s assessment may change in the future due to the occurrence of certain events, such as adverse judgments, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the Company s results of operations, financial position or cash flows.

Other

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on the Company s financial position, results of operations or cash flows. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and all subject to inherent uncertainties; therefore, management s view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on the Company s financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated.

Indemnifications

The Company provides certain indemnifications in relation to dispositions of assets. These indemnifications typically relate to disputes, litigation or tax matters existing at the date of disposition. No liability has been recognized in connection with these indemnifications.

(10) INCOME TAXES

The provision (benefit) for income taxes included the following components:

	2014	2013	2012
	(in millions)		
Current:			
Federal	$11	$(12)	$16
State	10	1	3
	21	(11)	19
Deferred:			
Federal	501	408	(388)
State	2	88	(72)
Foreign	1	1	(2)

	504	497	(462)
Provision (benefit) for income taxes	$525	$486	$(443)

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The provision for income taxes was an effective rate of 36% in 2014, 41% in 2013 and 39% in 2012. The following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

	2014	2013	2012
	(in millions)		
Expected provision (benefit) at federal statutory rate	$507	$417	$(403)
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	58	53	(44)
Nondeductible expenses	3	3	2
State rate redetermination	(48)	4	2
Other	5	9	
Provision (benefit) for income taxes	$525	$486	$(443)

The components of the Company s net deferred tax liability as of December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$2,504	$2,115
Derivative activity	122	13
Other	21	11
	2,647	2,139
Deferred tax assets:		
Accrued compensation	23	16
Alternative minimum tax credit carryforward	131	77
Stored natural gas	5	9
Accrued pension costs	17	2
Asset retirement obligations	79	54
Net operating loss carryforward	318	412
Differences between book and tax basis of property - state	6	11
Other	8	7
	587	588
Net deferred tax liability	$2,060	$1,551

The net deferred tax liability as of December 31, 2014 was comprised of net long-term deferred income tax liabilities of $1,951 million, in addition to a net current deferred income tax liability of $109 million. The net deferred tax liability at December 31, 2013 was comprised of net long-term deferred income tax liabilities of $1,527 million, in addition to a net current deferred income tax liability of $24 million. In 2014, the Company paid $14 million in state income taxes and paid $14 million in federal income taxes. In 2013, the Company paid $3 million in state income taxes and paid $16 million in federal income taxes. The Company s net operating loss carryforward as of December 31, 2014 was $988 million and $556 million for federal and state reporting purposes, respectively, the majority of which will expire between 2028 and 2034. As of December 31, 2014, the Company has recorded a $5 million valuation allowance against its deferred tax asset for various state net operating losses. The Company also had an alternative minimum tax credit carryforward of $131 million and a statutory depletion carryforward of $13 million as of December 31, 2014.

Our effective tax rate decreased in 2014 as compared with 2013. This was primarily due to a redetermination of the deferred state tax liability to reflect updated state apportionment factors in certain states.

Deferred tax assets relating to tax benefits of employee stock option grants have been reduced to reflect exercises in 2014. Some exercises resulted in tax deductions in excess of previously recorded benefits based on the option value at the time of the grant (windfalls). Although these additional tax benefits or windfalls are reflected in net operating loss

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carryforwards, the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable. Accordingly, since the tax benefit does not reduce the Company s current taxes payable in 2014 due to net operating loss carryforwards, these windfall tax benefits are not reflected in its net operating losses in deferred tax assets for 2014. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets for 2014 were $152 million.

The Company has an income tax net operating loss carryforward related to its Canadian operations of $26 million, and has expiration dates of 2030 through 2034. The Company assesses the available positive and negative evidence to estimate if sufficient future taxable income will be generated to utilize the existing deferred tax asset associated with the Canadian net operating loss. Based on this assessment, the Company did not record a valuation allowance as of December 31, 2014.

A tax position must meet certain thresholds for any of the benefit of the uncertain tax position to be recognized in the financial statements. As of December 31, 2014, the amount of unrecognized tax benefits related to alternative minimum tax was $44 million. The uncertain tax position identified would not have a material effect on the effective tax rate. No material changes to the current uncertain tax position are expected within the next 12 months. As of December 31, 2014, the Company had accrued a liability of $1 million of interest related to this uncertain tax position. The Company recognizes penalties and interest related to uncertain tax positions in income tax expense.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	2014
	(in millions)
Unrecognized tax benefits at beginning of period	$ -
Additions based on tax positions related to the current year	15
Additions to tax positions of prior years	29
Settlements	-
Unrecognized tax benefits at end of period	$44

The income tax years 2011 to 2014 remain open to examination by the major taxing jurisdictions to which the Company is subject.

(11) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company s 2014 and 2013 activity related to asset retirement obligations:

	2014		2013
	(in millions)		
Asset retirement obligation at January 1	$134		$101
Accretion of discount	7		6
Obligations incurred	64	(1)	22
Obligations settled/removed	(4)		(2)
Revisions of estimates	6		7
Asset retirement obligation at December 31	$207		$134
Current liability	9		6
Long-term liability	198		128
Asset retirement obligation at December 31	$207		$134

[1] Obligations incurred include $42 million related to the Chesapeake Property Acquisition.

(12) RETIREMENT AND EMPLOYEE BENEFIT PLANS

401(k) Defined Contribution Plan

The Company has a 401(k) defined contribution plan covering eligible employees. The Company expensed $3 million, $3 million and $2 million of contribution expense in 2014, 2013 and 2012, respectively. Additionally, the Company capitalized $3 million, $3 million and $3 million of contributions in 2014, 2013 and 2012, respectively, directly related to the acquisition, exploration and development activities of the Company s natural gas and oil properties or directly related to the construction of the Company s gathering systems.

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Defined Benefit Pension and Other Postretirement Plans

Prior to January 1, 1998, the Company maintained a traditional defined benefit plan with benefits payable based upon average final compensation and years of service. Effective January 1, 1998, the Company amended its pension plan to become a cash balance plan on a prospective basis for its non-bargaining employees. A cash balance plan provides benefits based upon a fixed percentage of an employee s annual compensation. The Company s funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plan provides contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages.

Substantially all employees are covered by the Company s defined benefit pension and postretirement benefit plans. The Company accounts for its defined benefit pension and other postretirement plans by recognizing the funded status of each defined pension benefit plan and other postretirement benefit plan on the Company s balance sheet. In the event a plan is overfunded, the Company recognizes an asset. Conversely, if a plan is underfunded, the Company recognizes a liability.

The following provides a reconciliation of the changes in the plans benefit obligations, fair value of assets, and funded status as of December 31, 2014 and 2013:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
	(in millions)			
Change in benefit obligations:				
Benefit obligation at January 1	$103	$105	$12	$12
Service cost	13	14	2	2
Interest cost	5	4	1	
Participant contributions				
Actuarial loss	21	(11)	3	(2)
Benefits paid	(8)	(8)		
Plan amendments				
Settlements		(1)		
Benefit obligation at December 31	$134	$103	$18	$12

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
	(in millions)			
Change in plan assets:				
Fair value of plan assets at January 1	$99	$83	$	$
Actual return on plan assets	5	12		
Employer contributions	12	13		

Participant contributions				
Benefits paid	(8)	(8)		
Settlements		(1)		
Fair value of plan assets at December 31	$108	$99	$	$
Funded status of plans at December 31	$(26)	$(4)	$(18)	$(12)

The Company uses a December 31 measurement date for all of its plans and had liabilities recorded for the underfunded status for each period as presented above.

The change in accumulated other comprehensive income related to the pension plans was a loss of $23 million ($14 million after tax) for the year ended December 31, 2014 and a gain of $19 million ($12 million after tax) for the year ended December 31, 2013. The change in accumulated other comprehensive income related to the other postretirement benefit

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plan was a loss of $2 million ($1 million after tax) for the year ended December 31, 2014 and was a gain of $2 million ($1 million after tax) for the year ended December 31, 2013. Included in accumulated other comprehensive income as of December 31, 2014 and 2013 was a $41 million loss ($24 million net of tax) and a $16 million loss ($10 million net of tax), respectively, related to the Company s pension and other postretirement benefit plans. For the year ended December 31, 2014, $25 million was classified to accumulated other comprehensive income primarily driven by actuarial loss adjustments. Amortization of prior period service cost reclassified from accumulated other comprehensive income to general and administrative expenses for the year was immaterial.

The amount in accumulated other comprehensive income that is expected to be recognized as a component of net periodic benefit cost during 2015 is a $2 million net loss.

The pension plans projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2014 and 2013 are as follows:

	2014	2013
	(in millions)	
Projected benefit obligation	$134	$103
Accumulated benefit obligation	$129	$100
Fair value of plan assets	$108	$99

Pension and other postretirement benefit costs include the following components for 2014, 2013 and 2012:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
	(in millions)					
Service cost	$13	$14	$11	$2	$2	$2
Interest cost	5	4	4	1	1	
Expected return on plan assets	(7)	(6)	(5)			
Amortization of transition obligation						
Amortization of prior service cost						
Amortization of net loss	1	2	1			
Net periodic benefit cost	12	14	11	3	3	2
Settlements and curtailments		0				
Total benefit cost	$12	$14	$11	$3	$3	$2

Amounts recognized in other comprehensive income for the year ended December 31, 2014 were as follows:

	Pension Benefits	Other Postretirement Benefits
	(in millions)	
Net actuarial loss arising during the year	$ (23)	$ (2)
Amortization of prior service cost		
Amortization of net loss		
Settlements		
Tax effect	9	1
	$ (14)	$ (1)

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The assumptions used in the measurement of the Company s benefit obligations as of December 31, 2014 and 2013 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Discount rate	4.25 %	5.00 %	4.25 %	5.00 %
Rate of compensation increase	4.50 %	4.50 %	n/a	n/a

The assumptions used in the measurement of the Company s net periodic benefit cost for 2014, 2013 and 2012 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Discount rate	5.00 %	4.00 %	5.00 %	5.00 %	4.00 %	5.00 %
Expected return on plan assets	7.00 %	7.00 %	7.50 %	n/a	n/a	n/a
Rate of compensation increase	4.50 %	4.50 %	4.50 %	n/a	n/a	n/a

The expected return on plan assets for the various benefit plans is based upon a review of the historical returns experienced, combined with the future expected returns based upon the asset allocation strategy employed. The plans seek to achieve an adequate return to fund the obligations in a manner consistent with the federal standards of the Employee Retirement Income Security Act and with a prudent level of diversification.

For measurement purposes, the following trend rates were assumed for 2014 and 2013:

	2014	2013
Health care cost trend assumed for next year	8 %	8 %
Rate to which the cost trend is assumed to decline	5 %	5 %
Year that the rate reaches the ultimate trend rate	2033	2032

Assumed health care cost trend rates have a significant effect on the amounts for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on the total service and interest cost components	$	$
Effect on postretirement benefit obligations	$3	$(2)

Pension Payments and Asset Management

In 2014, the Company contributed $12 million to its pension plans and $0.1 million to its other postretirement benefit plan. The Company expects to contribute $12 million to its pension plans and $1 million to its other postretirement benefit plan in 2015. No plan assets are expected to be returned to the Company during the next twelve months.

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The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Pension Benefits		Other Postretirement Benefits	
(in millions)			
2015	$6	2015	$1
2016	$8	2016	$1
2017	$8	2017	$1
2018	$10	2018	$1
2019	$11	Years 2019-2023	$9
Years 2020-2024	$65		

The Company s overall investment strategy is to provide an adequate pool of assets to support both the long-term growth of plan assets and to ensure adequate liquidity exists for the near-term benefit payment of obligations to participants, retirees and beneficiaries. The Benefits Administration Committee of the Company administers the Company s pension plan assets. The Benefits Administration Committee believes long-term investment performance is a function of asset-class mix and restricts the composition of pension plan assets to a combination of cash and cash equivalents, domestic equity markets, international equity markets or investment grade fixed income assets.

The table below presents the allocations targeted by the Benefits Administration Committee and the actual weighted-average asset allocation of the Company s pension plan as of December 31, 2014, by asset category. The asset allocation targets are subject to change and the Benefits Administration Committee allows for its actual allocations to deviate from target as a result of current and anticipated market conditions. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

	Pension Plan Asset Allocations	
Asset category:	Target	Actual
Equity securities:		
U.S. Equity(1)	35 %	36 %
Non-U.S. Developed Equity(2)	30 %	27 %
Emerging Markets Equity(3)	5 %	5 %
Opportunistic(4)	%	%
Fixed income(5)	29 %	29 %
Cash(6)	1 %	3 %
Total	100 %	100 %

(1) Asset category above includes the following equity securities in the table below: U.S. large cap growth equity, U.S. large cap value equity, U.S. large cap core equity, and U.S. small cap equity.
(2) Asset category above includes Non-U.S. equity securities in the table below.
(3) Asset category above includes Emerging markets equity securities below.
(4) Asset category above includes none of the securities in the table below.
(5) Asset category above includes Fixed income pension plan assets in the table below.
(6) Asset category above includes Cash and cash equivalents pension plan assets in the table below.

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Utilizing the fair value hierarchy described in Note 7 Fair Value Measurements, the Company s fair value measurement of pension plan assets as of December 31, 2014 are as follows:

Asset category:	Total (in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Equity securities:				
U.S. large cap growth equity(1)	$8	$ 8	$	$
U.S. large cap value equity(2)	9	9		
U.S. large cap core equity(3)	19		19	
U.S. small cap equity(4)	3	3		
Non-U.S. equity(5)	29	29		
Emerging markets equity(6)	5	5		
Fixed income (7)	31		31	
Cash and cash equivalents	4	4		
Total	$108	$ 58	$ 50	$

(1) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.
(2) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.
(3) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.
(4) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(5) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(6) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(7) Institutional funds that seek an investment return that approximates, as closely as practicable, before expenses, the performance of the Barclays U.S. Intermediate Credit Bond Index over the long term and the Barclays Long U.S. Corporate Bond Index over the long-term.

Utilizing the fair value hierarchy described in Note 7 Fair Value Measurements, the Company s fair value measurement of pension plan assets at December 31, 2013 are as follows:

Asset category:	Total (in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Equity securities:				
U.S. large cap growth equity(1)	$8	$ 8	$	$

U.S. large cap value equity(2)	8	8		
U.S. large cap core equity(3)	16		16	
U.S. small cap equity(4)	3	3		
Non-U.S. equity(5)	31	31		
Emerging markets equity(6)	6		6	
Fixed income (7)	26		26	
Cash and cash equivalents	1	1		
Total	$99	$ 51	$ 48	$

(1) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.
(2) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.
(3) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.
(4) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(5) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(6) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(7) An institutional fund that seeks to replicate the performance of the Barclays Capital Long-Term Corporate Bond Index before fees through a sampling process.

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The Company s pension plan assets that are classified as Level 1 are due to the pension plan s investments comprising either cash or investments in open-ended mutual funds which produce a daily net asset value that is validated with a sufficient level of observable activity to support classification of the fair value measurement as Level 1. The Company s Level 2 pension plan assets represent investments in institutional funds. These equity securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers. No concentration of risk arising within or across categories of plan assets exists due to any significant investments in a single entity, industry, country or investment fund.

(13) STOCK-BASED COMPENSATION

The Southwestern Energy Company 2013 Incentive Plan (2013 Plan) was adopted in February 2013 and approved by stockholders in May 2013. The 2013 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2013 Plan replaced the Southwestern Energy Company 2004 Stock Incentive Plan, the Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan), and the Southwestern Energy Company 2002 Employee Stock Incentive Plan (2002 Plan) but did not affect prior awards under those plans which remained valid and some of which are still outstanding. The awards under the prior plans have been adjusted for stock splits as permitted under such plans.

The 2013 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units to employees, officers, and directors that in the aggregate do not exceed 20,500,000 shares. The types of incentives that may be awarded are comprehensive and are intended to enable the Company s board of directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2013 Plan.

As initially adopted, the 2004 Plan, the 2000 Plan, and the 2002 Plan provided for grants of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock that in the aggregate did not exceed 16,800,000, 1,250,000, and 300,000 shares, respectively, to employees who are not officers or directors of the Company under provisions of Section 16 of the Securities Exchange Act of 1934, as amended. The Company may utilize treasury shares, if available, or authorized but unissued shares when a stock option is exercised or when restricted stock is granted.

The Company measures the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. All options are issued at fair market value at the date of grant and expire seven years from the date of grant for awards under both the 2013 Plan and the 2004 Plan and ten years from the date of grant for awards under all other plans. Generally, stock options granted to employees and directors vest ratably over three years from the grant date. The Company issues shares of restricted stock to employees and directors which generally vest over four years. The Company recognizes stock-based compensation expense on a straight-line basis over the requisite service period of the individual grants with the exception of awards granted to participants who have reached retirement age or will reach retirement age during the vesting period. Restricted stock and stock options granted to participants on or after December 6, 2013 immediately vest upon death, disability, or retirement (subject to a minimum of three years of service).

Stock Options

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2014, 2013 and 2012:

2014	2013	2012
(in millions)		

Stock-based compensation cost related to stock options general and administrative expense	$	5	$	5	$	5
Stock-based compensation cost related to stock options capitalized	$	4	$	5	$	4

The Company also recorded a deferred tax asset of $3 million related to stock options in 2014, compared to deferred tax benefits of $4 million in 2013 and $2 million in 2012. A total of $13 million of unrecognized compensation cost related to the Company s unvested stock option and restricted stock grants. This cost is expected to be recognized over a weighted-average period of 2 years.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company s common stock and other factors. The Company uses historical data on exercise of stock options, post vesting

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forfeitures and other factors to estimate the expected term of the stock-based payments granted. The risk free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant.

Assumptions	2014	2013	2012
Risk-free interest rate	1.6%	1.5%	0.6%
Expected dividend yield			
Expected volatility	32.5%	38.6%	58.2%
Expected term	5 years	5 years	5 years

The following tables summarize stock option activity for the years 2014, 2013 and 2012 and provide information for options outstanding at December 31 of each year:

	2014		2013		2012	
	Number of Shares (in thousands)	Weighted Average Exercise Price	Number of Shares (in thousands)	Weighted Average Exercise Price	Number of Shares (in thousands)	Weighted Average Exercise Price
Options outstanding at January 1	3,313	$35.70	3,650	$29.84	4,743	$21.24
Granted	835	32.31	573	38.95	613	34.34
Exercised	(402)	30.60	(831)	12.12	(1,608)	5.71
Forfeited or expired	(124)	37.80	(75)	37.31	(98)	37.76
Options outstanding at December 31	3,622	$35.41	3,313	$35.70	3,650	$29.84

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Options Outstanding at December 31, 2014 (in thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at December 31, 2014 (in thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)
$27.09-$29.69	21	28.42	2.9	17	28.53	2.5
$30.23-$35.91	1,744	32.04	4.9	819	32.83	3.1
$36.22-$39.91	1,443	37.52	4.3	1,117	37.10	3.9
$40.15-$51.47	414	42.64	2.9	324	41.56	1.9
	3,622	$35.41	4.4	$2,277	$36.13	3.3

The weighted-average grant-date fair value of options granted during the years 2014, 2013 and 2012 was $10.16, $13.39, and $16.91, respectively. The total intrinsic value of options exercised during 2014, 2013 and 2012 was $4 million, $22 million and $44 million, respectively.

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Restricted Stock

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
	(in millions)		
Stock-based compensation cost related to restricted stock grants general and administrative expense	$10	$7	$6
Stock-based compensation cost related to restricted stock grants capitalized	$12	$7	$6

The Company also recorded a deferred tax liability of $10 million related to restricted stock for the year ended December 31, 2014, compared to deferred tax liabilities of $15 million for 2013 and $1 million for 2012. As of December 31, 2014, there was $75 million of total unrecognized compensation cost related to unvested shares of restricted stock that is expected to be recognized over a weighted-average period of 3.1 years.

The following table summarizes the restricted stock activity for the years 2014, 2013 and 2012 and provides information for restricted stock outstanding at December 31 of each year:

	2014		2013		2012	
	Number of Shares (in thousands)	Weighted Average Grant Date Fair Value	Number of Shares (in thousands)	Weighted Average Grant Date Fair Value	Number of Shares (in thousands)	Weighted Average Grant Date Fair Value
Unvested shares at January 1	1,771	$37.55	1,118	$35.64	1,020	$36.71
Granted	1,295	30.89	1,109	38.92	537	34.39
Vested	(548)	37.12	(382)	36.29	(344)	36.50
Forfeited	(142)	37.91	(74)	35.81	(95)	36.97
Unvested shares at December 31	2,376	$34.00	1,771	$37.55	1,118	$35.64

The fair values of the grants were $40 million for 2014, $43 million for 2013 and $19 million for 2012. The total fair value of shares vested were $20 million for 2014, $14 million for 2013 and $13 million for 2012.

Equity-Classified Performance Units

The Company recorded the following compensation costs related to equity-classified performance units for the years ended December 31, 2014. The performance units include a market condition based on Relative Total Shareholder Return (TSR) and a performance condition based on the Company s Present Value Index (PVI). The fair value of the TSR market condition of the performance units is based on a Monte Carlo model and is amortized to compensation expense on a straight-line basis over the vesting period of the award. The fair value of the PVI performance condition of the performance units is based on the closing price of the Company s common stock at the grant date and amortized to compensation expense on a straight line basis over the vesting period of the award.

2014

	(millions)
Stock-based compensation cost related to performance units - general and administrative expense	$3
Stock-based compensation cost related to performance units - capitalized	$2

The Company also recorded a deferred tax asset of $2 million related to equity-based performance units for the year ended December 31, 2014, compared to no deferred tax recorded in 2013 and 2012. As of December 31, 2014, there was $24 million of total unrecognized compensation cost related to unvested equity-based performance units that is expected to be recognized over a weighted-average period of 3 years.

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The following table summarizes performance unit activity to be paid out in Company stock for the twelve months ended December 31, 2014 and provides information for unvested units as of December 31, 2014:

	2014	
	Number of Units (1)	Weighted Average Grant Date Fair Value
Unvested shares at January 1	-	$ -
Granted	359	40.44
Vested	(111)	40.44
Forfeited	(25)	40.44
Unvested shares at December 31	223	$ 40.44

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares may range from a minimum of zero shares to a maximum of two shares contingent upon the actual performance against the Performance Measures.

Liability-Classified Performance Units

Certain employees were provided performance units vesting equally over three years. The payout of these units is based on certain metrics, such as total shareholder return and reserve replacement efficiency, compared to a predetermined group of peer companies and Company goal. At the end of each performance period, the value of the vested performance units, if any, is paid in cash. The Company paid $25 million related to the vested performance units in 2014, $3 million in 2013, and $19 million in 2012. As of December 31, 2014 and 2013, the Company s liability under the performance unit agreements was $51 million and $45 million, respectively.

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(14) SEGMENT INFORMATION

The Company s reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced natural gas volumes and through gathering fees associated with the transportation of natural gas to market.

Summarized financial information for the Company s reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense, and other income (loss). The Other column includes items not related to the Company s reportable segments including real estate and corporate items.

	Exploration and Production (in millions)		Midstream Services	Other	Total
2014					
Revenues from external customers	$2,850		$ 1,188	$	$4,038
Intersegment revenues	12		3,170		3,182
Operating income (loss)	1,013		361	(1)	1,373
Other loss, net	(3)		(1)		(4)
Gain (loss) on derivatives	142		(1)	(2)	139
Depreciation, depletion and amortization expense	884		58		942
Interest expense(1)	47		12		59
Provision for income taxes(1)	402		123		525
Assets	13,018	(3)	1,554	353	14,925
Capital investments(4)	7,254		144	49	7,447
2013					
Revenues from external customers	$2,398		$ 973	$	$3,371
Intersegment revenues	6		2,374		2,380
Operating income	879		325		1,204
Other income (loss), net	3			(1)	2
Gain on derivatives	26				26
Depreciation, depletion and amortization expense	735		51	1	787
Interest expense(1)	30		11	1	42
Provision (benefit) for income taxes(1)	368		119	(1)	486
Assets	6,357	(3)	1,427	264	8,048
Capital investments(4)	2,052		158	25	2,235
2012					
Revenues from external customers	$1,965		$ 765	$	$2,730
Intersegment revenues	(1)		1,598	3	1,600
Operating income (loss)	(1,396)	(2)	294	1	(1,101)
Other income (loss), net	(1)			2	1
Loss on derivatives	(15)				(15)
Depreciation, depletion and amortization expense	766		44	1	811

Impairment of natural gas and oil properties	1,940				1,940
Interest expense(1)	20		14	1	35
Provision (benefit) for income taxes(1)	(549)		105	1	(443)
Assets	5,194	(3)	1,273	271	6,738
Capital investments(4)	1,861		165	55	2,081

(1) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as they are incurred at the corporate level.
(2) Includes a $1,940 million non-cash ceiling test impairment of the Company s natural gas and oil properties.

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(3) Includes office, technology, drilling rigs and other ancillary equipment not directly related to natural gas and oil property acquisition, exploration and development activities.

(4) Capital investments include an increase of $155 million for 2014 and a decrease of $25 million and $37 million for 2013 and 2012, respectively, related to the change in accrued expenditures between years.

Included in intersegment revenues of the Midstream Services segment are approximately $2.8 billion, $2.0 billion and $1.3 billion for 2014, 2013 and 2012, respectively, for marketing of the Company s E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. For 2014, 2013, and 2012, capital investments within the E&P segment include $11 million, $35 million, and $12 respectively, related to the Company s activities in Canada. As of December 31, 2014, 2013, and 2012, E&P assets include $77 million, $79 million, $44 million related to the Company s activities in Canada.

(15) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2014 and 2013:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(in millions, except per share amounts)			
	2014			
Operating revenues	$1,113	$1,035	$ 928	$ 962
Operating income	435	367	286	285
Net income	194	207	211	312
Earnings per share - Basic	0.55	0.59	0.60	0.89
Earnings per share - Diluted	0.55	0.59	0.60	0.88
	2013			
Operating revenues	$734	$862	$ 868	$ 907
Operating income	252	325	309	317
Net income	128	246	186	144
Earnings per share - Basic	0.36	0.70	0.53	0.41
Earnings per share - Diluted	0.36	0.70	0.53	0.41

(16) SUBSEQUENT EVENTS

On January 21, 2015, the Company completed concurrent underwritten public offerings of 30,000,000 shares of its common stock and 34,500,000 depositary shares (both share counts include shares issued as a result of the underwriters exercising their options to purchase additional shares). Net proceeds from the offerings totaled approximately $2.3 billion after underwriting discounts and offering expenses. The common stock offering was priced at $23.00 per share. Net proceeds, after underwriting discount and expenses, from the common stock offering were approximately $669 million. Net proceeds, after underwriting discount and expenses, from the depositary share offering were approximately $1.7 billion. Each depositary share represents a 1/20th interest in a share of the Company's 6.25% Series B Mandatory Convertible Preferred Stock, with a liquidation preference of $1,000 per share (equivalent to a $50 liquidation preference per depositary share). The proceeds from the offerings were used to partially repay borrowings under the Company s $4.5 billion 364-day bridge term loan facility.

On January 23, 2015, the Company completed a public offering of $350 million aggregate principal amount of its 3.300% senior notes due 2018 (the 2018 Notes), $850 million aggregate principal amount of its 4.050% senior notes due 2020 (the 2020 Notes) and $1 billion aggregate principal amount of its 4.950% senior notes due 2025 (the 2025 Notes and together with the 2018 Notes and the 2020 Notes, the Notes), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. The proceeds from the offering were used to repay all principal and interest remaining outstanding under the Company s $4.5 billion 364-day bridge term loan facility and were used to repay a portion of amounts outstanding under the Company s revolving credit facility.

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On January 27, 2015, the Company closed the Statoil Property Acquisition to purchase certain oil and natural gas assets covering approximately 30,000 acres in West Virginia and southwest Pennsylvania comprising approximately 20% of Statoil s interests in that acreage for $365 million, after environmental and title adjustments, and subject to customary post-closing adjustments.

On January 30, 2015, the Company closed the WPX Property Acquisition to purchase approximately 46,700 net acres in northeast Pennsylvania for an adjusted purchase price of $288 million, subject to customary post-closing adjustments.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of its management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of its disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC s rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of December 31, 2014 at a reasonable assurance level. There were no changes in our internal control over financial reporting during the three months ended December 31, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management has excluded the oil and gas assets from a subsidiary of Chesapeake Energy Corporation in West Virginia and southwest Pennsylvania (Chesapeake Property Acquisition) from its assessment of internal control over financial reporting as of December 31, 2014 as the Chesapeake Property Acquisition was acquired during 2014. The total assets and total revenues of the Chesapeake Property Acquisition represent approximately 33% and 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.

Management s Report on Internal Control Over Financial Reporting is included on page 70 of this Annual Report.

PricewaterhouseCoopers LLP s report on Southwestern Energy s internal control over financial reporting is included in its Report of Independent Registered Public Accounting Firm on page 71 of this Annual Report.

ITEM 9B. OTHER INFORMATION

There was no information required to be disclosed in a current report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2014, that was not reported on such form.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

EXECUTIVE OFFICERS OF THE REGISTRANT4

Name	Officer Position	Age	Years Served as Officer
Steven L. Mueller	Chairman of the Board and Chief Executive Officer	61	6
William J. Way	President and Chief Operating Officer	55	3
Mark K. Boling	Executive Vice President and President V+ Development Solutions	57	13
Jeffrey B. Sherrick	Executive Vice President Corporate Development	60	6
R. Craig Owen	Senior Vice President and Chief Financial Officer	45	6
John C. Ale	Senior Vice President, General Counsel and Secretary	60	1

Mr. Mueller was appointed to his present position as Chairman of the Board in May 2014. Mr. Mueller was appointed Chief Executive Officer in May 2009 and was elected to the Board of Directors in July 2009. Mr. Mueller joined us as President and Chief Operating Officer in June 2008. He joined us from CDX Gas, LLC, where he was employed as Executive Vice President from September 2007 to May 2008. From 2001 until 2007, Mr. Mueller served first as the Senior Vice President and General Manager Onshore and later as the Executive Vice President and Chief Operating Officer of The Houston Exploration Company. A graduate of the Colorado School of Mines, Mr. Mueller has over 30 years of experience in the oil and natural gas industry and has served in multiple operational and managerial roles at Tenneco Oil Company, Fina Oil Company, American Exploration Company and Belco Oil & Gas Company.

Mr. Way was appointed to his present position as President in December 2014. Mr. Way joined the Company in 2011 as Executive Vice President and Chief Operating Officer of Southwestern Energy. Prior to joining the Company, he was Senior Vice President, Americas of BG Group plc with responsibility for E&P, Midstream and LNG operations in the United States, Trinidad and Tobago, Chile, Bolivia, Canada and Argentina. He is a graduate of Texas A&M University with a degree in Industrial Engineering and has an MBA from The Massachusetts Institute of Technology.

Mr. Boling was appointed to his present position as in December 2012. He joined us as Senior Vice President, General Counsel and Secretary in January 2002, positions in which he served until November 2013. He became Executive Vice President, General Counsel and Secretary of the Company later in 2002. Prior to joining the company, Mr. Boling had a private law practice in Houston specializing in the natural gas and oil industry from 1993 to 2002. Previously, Mr. Boling was a partner with Fulbright and Jaworski L.L.P., where he was employed from 1982 to 1993.

Mr. Sherrick was appointed to his present position in December 2013. He joined the Company in October 2008 as Senior Vice President, U.S. Exploitation of Southwestern Energy s subsidiaries SEECO, Inc. and Southwestern Energy Production Company. From 2005 to 2007, Mr. Sherrick served as the Senior Vice President, Corporate Development of The Houston Exploration Company. In 2004, he served as the Senior Vice President, Production and Nonregulated Services of El Paso Production Company. From 1999 through 2002, he served as the Chairman, CEO and President of Enron Global Exploration and Production Inc., and prior to that he served in multiple operational and managerial roles at Enron Oil & Gas Company, and Tenneco Oil Company. Mr. Sherrick is a graduate of Marietta College with a Bachelor of Science degree in Petroleum Engineering.

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Mr. Owen was appointed to his present position in October 2012. He joined the Company as Controller in July 2008 and was promoted to Senior Vice President in May 2012. Immediately prior to joining the Company, he was Controller, Operations Accounting of Anadarko Petroleum Corporation, where he had held various managerial positions since 2001. Prior to Anadarko Petroleum, Mr. Owen was a business assurance manager at PricewaterhouseCoopers LLP in Houston, Texas, serving clients in the energy, insurance, banking and investment industries, and held various financial reporting roles with ARCO Pipe Line Company and Hilcorp Energy Company. Mr. Owen holds a bachelor of business administration degree in accounting from Texas A&M University and is a Certified Public Accountant.

Mr. Ale joined the Company in November 2013 as Senior Vice President, General Counsel and Secretary. Prior to Southwestern Energy, Mr. Ale was Vice President and General Counsel of Occidental Petroleum Corporation. Previously, he was a partner with Skadden, Arps, Slate, Meagher & Flom LLP and Vinson & Elkins LLP. Mr. Ale served as a law clerk to Chief Justice Warren E. Burger of the U.S. Supreme Court and to Judge Edward Tamm of the U.S. Court of Appeals for the D.C. Circuit. He holds a Juris Doctorate degree from the University of Virginia School of Law and a Bachelor of Arts degree in economics from the University of Virginia College of Arts and Sciences.

All executive officers are elected at the Annual Meeting of the Board of Directors for one-year terms or until their successors are duly elected. There are no arrangements between any officer and any other person pursuant to which he was selected as an officer. There is no family relationship between any of the Company s executive officers or between any of them and the Company s directors.

The definitive proxy statement to holders of the Company s common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Stockholders to be held on or about May 19, 2015 (the Proxy Statement), is hereby incorporated by reference for the purpose of providing information about the Company s directors, and for discussion of its audit committee and its audit committee financial expert. Refer to the sections Proposal No. 1: Election of Directors and Share Ownership of Management, Directors and Nominees in the Proxy Statement for information concerning our directors. Refer to the section Corporate Governance Committees of the Board of Directors in the 2015 Proxy Statement for discussion of its audit committee and its audit committee financial expert. Information concerning the Company s executive officers is presented in Part I of this Annual Report. The Company refers you to the section Section 16(a) Beneficial Ownership Reporting Compliance in the Proxy Statement for information relating to compliance with Section 16(a) of the Exchange Act.

Southwestern Energy has adopted a code of ethics that applies to its Chief Executive Officer, Chief Financial Officer and Controller as well as other officers and employees. The full text of such code of ethics has been posted on the Company s website at www.swn.com, and is available free of charge in print to any stockholder who requests it. Requests for copies should be addressed to the Secretary at 10000 Energy Drive, Spring, Texas 77389.

ITEM 11. EXECUTIVE COMPENSATION

The Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation, compensation committee interlocks and insider participation as well as the Compensation Committee Report. Refer to the sections Compensation Discussion & Analysis, Executive Compensation, Outside Director Compensation, Compensation Committee Interlocks and Insider Participation and Compensation Committee Report in the Proxy Statement.

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

The Proxy Statement is hereby incorporated by reference for the purpose of providing information about securities authorized for issuance under our equity compensation plans and security ownership of certain beneficial owners and its management. For information about our equity compensation plans, refer to Equity Compensation Plans in its Proxy Statement. Refer to the sections Security Ownership of Certain Beneficial Owners and Share Ownership of Management, Directors and Nominees in the Company s Proxy Statement for information about security ownership of certain beneficial owners and its management and directors.

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

The Proxy Statement is hereby incorporated by reference for the purpose of providing information about certain relationships, related transactions and board independence. Refer to the sections Transactions with Related Persons, Share Ownership of Management, Directors and Nominees, and Compensation Discussion and Analysis for information about transactions with our executive officers, directors or management and to Corporate Governance Director Independence and Committees of the Board of Directors for information about director independence.

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ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The Proxy Statement is hereby incorporated by reference for the purpose of providing information about fees paid to the principal accountant and the audit committee s pre-approval policies and procedures. Refer to the section Relationship with Independent Registered Public Accounting Firm in the Proxy Statement and to Exhibit A thereto for information concerning fees paid to our principal accountant and the audit committee s pre-approval policies and procedures and other required information.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) The consolidated financial statements of Southwestern Energy and its subsidiaries and the report of independent registered public accounting firm are included in Item 8 of this Annual Report.

(2) The consolidated financial statements schedules have been omitted because they are not required under the related instructions, or are not applicable.

(3) The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Annual Report.

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SIGNATURES

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

SOUTHWESTERN ENERGY COMPANY

Dated: February 26, 2015BY:/s/ R. CRAIG OWEN

R. Craig Owen

Senior Vice President

and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 26, 2015.

. CRAIG OWEN

/s/ STEVEN L. MUELLER Steven L. Mueller	Director, Chairman of the Board, and Chief Executive Officer
/s/ R. CRAIG OWEN R. Craig Owen	Senior Vice President and Chief Financial Officer
/s/ JOSH C. ANDERS Josh C. Anders	Vice President, Controller
/s/ JOHN D. GASS John D. Gass	Director
/s/ CATHERINE A. KEHR Catherine A. Kehr	Director
/s/ GREG D. KERLEY Greg D. Kerley	Director
/s/ VELLO A. KUUSKRAA Vello A. Kuuskraa	Director
/s/ KENNETH R. MOURTON Kenneth R. Mourton	Director
/s/ ELLIOTT PEW Elliott Pew	Director
/s/ TERRY W. RATHERT Terry W. Rathert	Director

/s/ ALAN H. STEVENS Alan H. Stevens	Director

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EXHIBIT INDEX

Exhibit Number	Description
1.1	Common Stock Underwriting Agreement, dated January 14, 2015, between Southwestern Energy Company and, Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the underwriters named therein. (Incorporated by reference to Exhibit 1.1 to the Registrant s Current Report on Form 8-K filed on January 21, 2015)
1.2	Depositary Shares Underwriting Agreement, dated January 14, 2015, between Southwestern Energy Company and, Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the underwriters named therein. (Incorporated by reference to Exhibit 1.2 to the Registrant s Current Report on Form 8-K filed on January 21, 2015)
1.3	Underwriting Agreement, dated January 20, 2015, between Southwestern Energy Company and, Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the underwriters named therein (Incorporated by reference to Exhibit 1.1 to the Registrant s Current Report on Form 8-K filed on January 23, 2015)
2.1	Purchase Agreement dated as of October 14, 2014 between Southwestern Energy Production Company and Chesapeake Appalachia, L.L.C. (Incorporated by reference to Exhibit 2.1 to the Registrant s Current Report on Form 8-K filed on October 17, 2014)
3.1	Amended and Restated Certificate of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant s Current Report on Form 8-K filed May 24, 2010)
3.2	Amended and Restated Bylaws of Southwestern Energy Company, as amended on February 25, 2014. (Incorporated by reference to Exhibit 3.2 to the Registrant s Annual Report on Form 10-K filed February 27, 2014)
3.3	Certificate of Designations of 6.25% Series B Mandatory Convertible Preferred Stock (including form of stock certificate). (Incorporated by reference to Exhibit 3.1 to the Registrant s Current Report on Form 8-K filed on January 21, 2015)
3.4	Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock, dated April 9, 2009. (Incorporated by reference to Exhibit 3.1 to the Registrant s Current Report on Form 8-K filed on April 9, 2009)
4.1	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.4 to the Registrant s Current Report on Form 8-K/A filed August 3, 2006)
4.2	Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago, as trustee. (Incorporated by reference to Exhibit 4 to Amendment No. 1 to the Registrant s Registration Statement on Form S-3 (File No. 33-63895) filed on November 17, 1995)
4.3	First Supplemental Indenture between Southwestern Energy Company and J.P. Morgan Trust Company, N.A. (as successor to the First National Bank of Chicago) dated June 30, 2006. (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K/A filed August 3, 2006)
4.4	Second Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee (as successor to J.P. Morgan Trust Company, N.A.), dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K/A filed on May 8, 2008)
4.5	Indenture dated June 1, 1998 by and among NOARK Pipeline Finance, L.L.C. and The Bank of New York. (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed May 4, 2006)
4.6	First Supplemental Indenture dated May 2, 2006 by and among Southwestern Energy Company, NOARK Pipeline Finance, L.L.C., and UMB Bank, N.A., as trustee (as successor to the Bank of New York). (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed May 4, 2006)
4.7	

Second Supplemental Indenture between Southwestern Energy Company and UMB Bank, N.A., as trustee, dated June 30, 2006. (Incorporated by reference to Exhibit 4.3 to the Registrant s Current Report on Form 8-K/A filed August 3, 2006)

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4.8 Third Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and UMB Bank, N.A., as trustee, dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K/A filed on May 8, 2008)

4.9 Guaranty dated June 1, 1998 by Southwestern Energy Company in favor of The Bank of New York, as trustee, under the Indenture dated as of June 1, 1998 between NOARK Pipeline Finance L.L.C. and such trustee. (Incorporated by reference to Exhibit 4.6 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2005)

4.10 Indenture dated January 16, 2008 among Southwestern Energy Company, the Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed January 16, 2008)

4.11 Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee, dated as of March 5, 2012. (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed March 6, 2012)

4.12 Policy on Confidential Voting of Southwestern Energy Company. (Incorporated by reference to the Appendix of the Registrant s Definitive Proxy Statement (Commission File No. 1-08246) for the 2006 Annual Meeting of Stockholders)

4.13 Credit Agreement dated December 16, 2013 among Southwestern Energy Company, JPMorgan Chase Bank, NA, Bank of America, N.A., Wells Fargo N.A., The Royal Bank of Scotland PLC, Citibank, N.A. and the other lenders named therein, JPMorgan Chase Bank, NA, as administrative agent. (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed December 17, 2013)

4.14 Commitment Letter dated October 14, 2014 between Southwestern Energy Company, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Bank of America, N.A. (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed on October 17, 2014)

4.15 Bridge Term Loan Credit Agreement, dated December 19, 2014, among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, Citibank, N.A., JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and The Royal Bank of Scotland plc, as Co-Syndication Agents, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Sole Lead Arranger and Sole Bookrunner, and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed on December 23, 2014)

4.16 Term Loan Credit Agreement, dated December 19, 2014, among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Sole Lead Arranger and Sole Bookrunner, and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K filed on December 23, 2014)

4.17 Form of certificate for the 6.25% Series B Mandatory Convertible Preferred Stock. (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed on January 21, 2015)

4.18 Deposit Agreement, dated as of January 21, 2015, between Southwestern Energy Company and Computershare Trust Company, N.A., as depositary, on behalf of all holders from time to time of the receipts issued thereunder (including form of Depositary Receipt). (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed on January 21, 2015)

4.19 Form of Depositary Receipt for the Depositary Shares. (Incorporated by reference to Exhibit 4.3 to the Registrant s Current Report on Form 8-K filed on January 21, 2015)

4.20 Indenture, dated as of January 23, 2015 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed on January 23, 2015)

4.21 First Supplemental Indenture, dated as of January 23, 2015 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed on January 23, 2015)

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4.22 Form of 3.300% Notes due 2018. (Incorporated by reference to Exhibit 4.3 to the Registrant s Current Report on Form 8-K filed on January 23, 2015)
4.23 Form of 4.050% Notes due 2020. (Incorporated by reference to Exhibit 4.4 to the Registrant s Current Report on Form 8-K filed on January 23, 2015)
4.24 Form of 4.095% Notes due 2025. (Incorporated by reference to Exhibit 4.5 to the Registrant s Current Report on Form 8-K filed on January 23, 2015)
10.1 Form of Second Amended and Restated Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K/A filed August 3, 2006)
10.2 Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.3 Form of Amendment to Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company prior to 2011. (Incorporated by reference to Exhibit 10.3 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008)
10.4 Form of Executive Severance Agreement between Southwestern Energy Company and Executive Officers Post 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant s Annual Report on Form 10-K (Commission File No.1-08426) for the year ended December 31, 2012)
10.5 Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.2(b) to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.6 Amendment to Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.5 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008)
10.7 Second Amendment to Southwestern Energy Company Incentive Compensation Plan (Incorporated by reference to Exhibit 10.6 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
10.8 Southwestern Energy Company Supplemental Retirement Plan as amended. (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed on February 19, 2008)
10.9 Southwestern Energy Company Non-Qualified Retirement Plan as amended. (Incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K filed on February 19, 2008)
10.10 Amendment One to the Southwestern Energy Company Non-Qualified Retirement Plan (Incorporated by reference to Exhibit 10.9 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
10.11 Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000. (Incorporated by reference to the Appendix of the Registrant s Definitive Proxy Statement (Commission File No. 1-08246) for the 2000 Annual Meeting of Stockholders)
10.12 Southwestern Energy Company 2002 Employee Stock Incentive Plan, effective October 23, 2002. (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed on December 13, 2005)
10.13 Southwestern Energy Company 2002 Performance Unit Plan, as amended, effective December 8, 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2012)
10.14 Southwestern Energy Company 2004 Stock Incentive Plan. (Incorporated by reference to Appendix A to the Registrant s Proxy Statement dated March 29, 2004)

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10.15 Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Annex A of the Registrant s Proxy Statement filed April 8, 2013)

10.16 Southwestern Energy Company 2013 Incentive Plan Guidelines for Performance Unit Awards. (Incorporated by reference to Exhibit 10.16 to the Registrant s Annual Report on Form 10-K for the year ended December 31, 2013)

10.17 Southwestern Energy Company 2013 Incentive Plan Guidelines for Annual Incentive Awards. (Incorporated by reference to Exhibit 10.3 to the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.18 Southwestern Energy Company 2013 Incentive Plan Form of Incentive Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.4 to the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.19 Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.5 to the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.20 Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement for Directors. (Incorporated by reference to Exhibit 10.6 to the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.21 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement. (Incorporated by reference to Exhibit 10.7 to the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.22 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement for Directors. (Incorporated by reference to Exhibit 10.8 to the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.23 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement. (Incorporated by reference to Exhibit 10.9 to the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.24 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors. (Incorporated by reference to Exhibit 10.10 to the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.25 Form of Incentive Stock Option Agreement for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed on December 20, 2004)

10.26 Form of Non-Qualified Stock Option Agreement for non-employee directors for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K filed on December 20, 2004)

10.27 Form of Incentive Stock Option for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.4 to the Registrant s Current Report on Form 8-K filed on December 13, 2005)

10.28 Form of Restricted Stock Agreement for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.4 to the Registrant s Current Report on Form 8-K filed on December 13, 2005)

10.29 Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2005 and through December 8, 2011 (Incorporated by reference to Exhibit 10.4 to the Registrant s Current Report on Form 8-K filed on December 13, 2005)

10.30 Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08426) for the year ended December 31, 2012)

10.31 Master Lease Agreement by and between Southwestern Energy Company and SunTrust Leasing Corporation dated December 29, 2006. (Incorporated by reference to Exhibit 10.22 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2006)

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10.32	Guaranty by and between Southwestern Energy Company and Texas Gas Transmission, LLC, dated as of October 27, 2008. (Incorporated by reference to Exhibit 10.3 to the Registrant s Quarterly Report on Form 10-Q (Commission File No. 1-08246) for the period ended September 30, 2008)
10.33	Guaranty by and between Southwestern Energy Company and Fayetteville Express Pipeline, LLC dated September 30, 2008 (Incorporated by reference to Exhibit 10.22 to the Registrant s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008)
10.34	Retirement Letter Agreement dated February 24, 2012 between Southwestern Energy Company and Gene A. Hammons. (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed February 27, 2012)
10.35	Retirement Agreement dated August 11, 2009 between Southwestern Energy Company and Harold M. Korell. (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed on August 14, 2009)
10.36	Settlement Agreement, dated December 22, 2014, between Chesapeake Appalachia, L.L.C. and SWN Production Company, LLC (Incorporated by reference to Exhibit 10.3 to the Registrant s Current Report on Form 8-K filed on December 23, 2014)
21.1*	List of Subsidiaries.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95.1*	Mine Safety Disclosure.
99.1*	Reserve Audit Report of Netherland, Sewell & Associates, Inc., dated January 16, 2015.
101.INS*	Interactive Data File Instance Document
101.SCH*	Interactive Data File Schema Document
101.CAL*	Interactive Data File Calculation Linkbase Document
101.LAB*	Interactive Data File Label Linkbase Document
101.PRE*	Interactive Data File Presentation Linkbase Document
101.DEF*	Interactive Data File Definition Linkbase Document

*Filed herewith