Table of Contents

As filed with the Securities and Exchange Commission on September 30, 2013

Registration No. 333-189284

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 5
to

FORM S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

ANTERO RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1311**	**80-0162034**
(State or Other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(IRS Employer Identification Number)

1625 17th Street
Denver, Colorado 80202
(303) 357-7310
(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant's Principal Executive Offices)

Glen C. Warren, Jr.
President, Chief Financial Officer and Secretary
1625 17th Street
Denver, Colorado 80202
(303) 357-7310
(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Copies to:

W. Matthew Strock	**Ryan J. Maierson**
Matthew R. Pacey	**Latham & Watkins LLP**
Vinson & Elkins L.L.P.	**811 Main Street, Suite 3700**

1001 Fannin, Suite 2500
Houston, Texas 77002-6760
(713) 758-2222

Houston, Texas 77002
(713) 546-5400

Approximate date of commencement of proposed sale of the securities to the public:
As soon as practicable after the effective date of this Registration Statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933 check the following box: o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

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

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

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	**Amount to be Registered(1)**	**Proposed Maximum Offering Price Per Share(2)**	**Proposed Maximum Aggregate Offering Price(1)(2)**	**Amount of Registration Fee(3)**
Common Stock, par value $0.01 per share	34,500,000	$42.00	$1,449,000,000	$197,643.60

(1) Estimated pursuant to Rule 457(a) under the Securities Act of 1933, as amended. Includes 4,500,000 additional shares of common stock that the underwriters have the option to purchase.

(2) Estimated solely for the purpose of calculating the registration fee.

(3) The Registrant previously paid $136,400 of the total registration fee in connection with the previous filing of this Registration Statement.

The registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until this Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

Table of Contents

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state or jurisdiction where the offer or sale is not permitted.

Subject to Completion, dated September 30, 2013

PROSPECTUS

30,000,000 Shares

Antero Resources Corporation

Common Stock

This is the initial public offering of the common stock of Antero Resources Corporation. We are offering 30,000,000 shares of our common stock. The selling stockholder has granted the underwriters the option to purchase up to an additional 3,750,000 shares of common stock on the same terms and conditions if the underwriters sell more than 30,000,000 shares of common stock in this offering. We have granted the underwriters the option to purchase up to an additional 750,000 shares of common stock on the same terms and conditions if the underwriters sell more than 33,750,000 shares of common stock in this offering. Any exercise by the underwriters of their options to purchase additional shares of common stock will be made initially with respect to the 3,750,000 additional shares of common stock to be sold by the selling stockholder and then with respect to the 750,000 additional shares of common stock to be sold by us. We will not receive any proceeds from the sale of shares held by the selling stockholder. No public market currently exists for our common stock.

We have been approved to list our common stock on the New York Stock Exchange under the symbol "AR".

We anticipate that the initial public offering price will be between $38.00 and $42.00 per share.

Investing in our common stock involves risk. See "Risk Factors" beginning on page 26 of this prospectus.

	Per share	Total
Price to the public	$	$
Underwriting discounts and commissions payable by us	$	$
Proceeds to us (before expenses)	$	$

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of common stock to purchasers on or about , 2013.

Barclays	**Citigroup**	**J.P. Morgan**
Credit Suisse	**Jefferies**	**Wells Fargo Securities**

Morgan Stanley	**TD Securities**	**Tudor, Pickering, Holt & Co.**

Baird	**BMO Capital Markets**	**Capital One Securities**
Raymond James	**Scotiabank / Howard Weil**	**Credit Agricole CIB**
KeyBanc Capital Markets	**Mitsubishi UFJ Securities**	**BB&T Capital Markets**
	Comerica Securities	

Prospectus dated , 2013

Table of Contents

TABLE OF CONTENTS

You should rely only on the information contained in this prospectus and any free writing prospectus prepared by us or on behalf of us or to which we have referred you. Neither we nor the selling stockholder has authorized anyone to provide you with information different from that contained in this prospectus and any free writing prospectus. We take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. We and the selling stockholder are offering to sell shares of common stock and seeking offers to buy shares of common stock only in jurisdictions where offers and sales are permitted. The information in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of the common stock. Our business, financial condition, results of operations and prospects may have changed since that date.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. See "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications and other published independent sources. Some data is also based on our good faith estimates. Although we believe these third-party sources are reliable as of their respective dates, neither we nor the underwriters have independently verified the accuracy or completeness of this information. The industry in which we operate is subject to a high degree of uncertainty and risk due to a variety of factors, including those described in the section entitled "Risk Factors." These and other factors could cause results to differ materially from those expressed in these publications.

Table of Contents

PROSPECTUS SUMMARY

This summary highlights some of the information contained in this prospectus and does not contain all of the information that may be important to you. You should read this entire prospectus and the documents to which we refer you before making an investment decision. You should carefully consider the information set forth under "Risk Factors," "Cautionary Statement Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and the related notes to those financial statements included elsewhere in this prospectus. Where applicable, we have assumed an initial public offering price of $40.00 per share (the midpoint of the price range set forth on the cover page of this prospectus). Unless otherwise indicated, the information presented in this prospectus assumes that the underwriters' options to purchase additional shares of common stock are not exercised. Unless otherwise indicated, the estimated reserve volumes presented in this prospectus are based on SEC pricing at June 30, 2013 (assuming ethane rejection), as described in " Our Properties Reserves." Certain operational terms used in this prospectus are defined in the "Glossary of Natural Gas and Oil Terms."

In this prospectus, references to "we," "us," "our" and the "Company" refer to Antero Resources LLC and its subsidiaries before the completion of our corporate reorganization and to Antero Resources Corporation and its subsidiaries as of and following the completion of our corporate reorganization. Please see "Corporate Reorganization." References to the "selling stockholder" refer to Antero Resources Investment LLC.

Our Company

We are an independent oil and natural gas company engaged in the exploitation, development and acquisition of natural gas, NGLs and oil properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. We are focused on creating shareholder value through the development of our large portfolio of repeatable, low cost, liquids-rich drilling opportunities in two of the premier North American shale plays. We currently hold approximately 329,000 net acres in the southwestern core of the Marcellus Shale and approximately 102,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 170,000 net acres of our Marcellus Shale leasehold are prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on a portion of our Marcellus Shale acreage in West Virginia that we believe is prospective for the dry gas Utica Shale. As of June 30, 2013, our estimated proved, probable and possible reserves were 6.3 Tcfe, 14.0 Tcfe and 7.4 Tcfe, respectively, and our proved reserves were 23% proved developed and 91% natural gas, assuming ethane rejection. As of June 30, 2013, our drilling inventory consisted of 4,576 identified potential horizontal well locations, approximately 64% of which are liquids-rich drilling opportunities.

Our management team has a proven track record of implementing geologically driven growth strategies in some of the most prominent unconventional plays across the United States, including the Barnett, Woodford, Marcellus and Utica Shales. Paul Rady, our Chairman and Chief Executive Officer, and Glen Warren, our President and Chief Financial Officer, founded our business in 2002. The majority of our management team has worked together at various times for over 30 years at Amoco Production Company, Barrett Resources Corporation, Pennaco Energy Inc. and Antero Resources. Our management team has created significant shareholder value through various past ventures, including the sale of two unconventional resource-focused upstream companies and one midstream company in the last 15 years.

We have been successful in targeting large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs and oil from unconventional formations. We have been early adopters of innovative hydraulic fracturing and completion techniques, having drilled over 450 horizontal wells in the Barnett, Woodford, Marcellus and Utica Shales. As a result of our horizontal drilling and completion expertise, and the predictable geologic structure throughout our largely contiguous land position in the southwestern core of the Marcellus Shale, we have drilled approximately 1.3 million lateral feet without encountering any faulting in our target zone. We have drilled and completed 199 horizontal wells in the Marcellus Shale with a 100% success rate to date. We define the term 100% success rate to mean that all wells were completed and produce in commercially viable quantities. With 15 rigs running, we are currently the most active driller in the Marcellus Shale based on information from RigData. We have begun to apply the expertise and approach we employ in the Marcellus Shale to the Utica Shale, and we believe we will be able to achieve similar success. We have drilled and completed 11 horizontal wells in the Utica Shale with a 100% success rate without encountering any faulting.

Our net daily production in the second quarter of 2013 averaged 458 MMcfe/d, including 4,160 Bbls/d of NGLs and oil. Further, our estimated average net daily production for the month of August 2013 was 594 MMcfe/d, including 8,630 Bbls/d of NGLs and oil. We grew proved reserves at a compounded annual growth rate of 96% from 2006 to 2012, despite the 2012 divestiture of our Arkoma and Piceance Basin properties. Additionally, from January 1, 2012 to June 30, 2013, we increased our Appalachian proved reserves by 47% to 6.3 Tcfe, assuming ethane rejection at each date.

The charts below illustrate the growth in our average net daily production on an overall basis since 2006 and in the Appalachian Basin since 2010:

Antero Average Net Daily Production

Antero Appalachian Basin Average Net Daily Production

---

(1) CAGR means compounded annual growth rate.

Our 2013 capital budget is $2.45 billion, including $1.45 billion for drilling and completion, substantially all of which is allocated to our operated drilling in liquids-rich gas areas. As of June 30, 2013, we had spent approximately $1.2 billion of our 2013 capital budget.

Our Properties

Marcellus Shale

We believe that the Marcellus Shale is a premier North American shale play due to its high well recoveries relative to drilling and completion costs, broad aerial extent, relatively homogeneous high-quality reservoir characteristics and significant hydrocarbon resources in place. Based on these attributes, as well as drilling results publicly released by other operators, we believe that the Marcellus Shale offers some of the most attractive single-well rates of return of all North American conventional and unconventional play types. We also believe that the Marcellus Shale has two core areas: the southwestern core in northern West Virginia and southwestern Pennsylvania and the northeastern core in northeastern Pennsylvania. According to RigData, as of September 2013, approximately 90% of the 91 drilling rigs operating in the Marcellus Shale were located in these two core areas.

Table of Contents

All of our approximately 329,000 net acres in the Marcellus Shale are located within the southwestern core. We have experienced virtually no geologic complexity in our drilling activities to date, which has contributed to what we believe to be a narrow and predictable band of expected well recoveries per 1,000 feet of lateral length on our wells. Further, the lower thermal maturity of the Marcellus Shale in the western half of the southwestern core yields liquids-rich natural gas and condensate, which allows for NGL processing that can significantly improve well economics. As of June 30, 2013, we had approximately 2,941 identified gross undrilled horizontal well locations in the Marcellus Shale.

For the three months ended June 30, 2013, we had average net daily production of 457 MMcfe/d in the Marcellus Shale. Further, our estimated average net daily production for the month of August 2013 in the Marcellus Shale was 549 MMcfe/d, including 6,528 Bbls/d of NGLs and oil. We currently have 15 rigs operating in the Marcellus Shale and expect to drill 135 wells in 2013, of which 74 had been drilled as of June 30, 2013. We believe our full cycle drilling, completion and operating costs on a per unit basis are among the lowest in the Marcellus Shale and the industry as a whole.

Utica Shale

Based on initial drilling results and the first two months of production for our 11 Utica wells, we believe that the Utica Shale is a premier North American shale play. We believe that the core area is located in the southern portion of the play, which has been defined by significant drilling activity by several operators. We own approximately 102,000 net acres in the core of the Utica Shale and expect to add to our sizeable land position. The proximity of our Utica acreage position to our operations in the Marcellus Shale allows us to capitalize on operating and midstream synergies. We are currently operating four drilling rigs in the Utica Shale and have completed 11 horizontal wells with strong results. We have had a 100% success rate and believe over 90% of our acreage has liquids-rich gas processing potential. We expect to drill 26 wells in the Utica Shale in 2013, of which 11 had been drilled as of June 30, 2013. As of June 30, 2013, we had approximately 720 identified gross undrilled horizontal well locations in the Utica Shale. For the three months ended June 30, 2013, we had average net daily production of 1 MMcfe/d in the Utica Shale. Further, our estimated average net daily production for the month of August 2013 in the Utica Shale was 45 MMcfe/d, including 2,102 Bbls/d of NGLs and oil.

Reserves

The following tables provide summaries of our estimated reserves as of June 30, 2013, assuming ethane "recovery" and ethane "rejection." Ethane rejection occurs when ethane is left in the wellhead gas stream when the gas is processed, rather than being separated out and sold as a liquid after fractionation. When ethane is left in the gas stream, the BTU content of the residue gas at the outlet of the processing plant is higher. Producers will elect to "reject" ethane when the price received for the higher BTU residue gas is greater than the price received for the ethane being sold as a liquid after fractionation. When ethane is recovered, the BTU content of the residue gas is lower, but a producer is then able to recover the value of the ethane sold as a separate NGL product. In addition, gas processing plants can produce the other NGL products (propane, normal butane, isobutane and natural gasoline) while rejecting ethane. The combination of infrastructure constraints in the Appalachian region and low ethane prices has resulted in many producers "rejecting" rather than "recovering" ethane. Although our reserve data as of December 31, 2012 assumed ethane recovery based on the reserve pricing methods required by the SEC, or SEC pricing, the current spot price environment has shifted to one that favors ethane rejection and therefore our reserve estimates as of June 30, 2013 assumed ethane rejection.

Table of Contents

SEC Pricing

	June 30, 2013	
	Estimated Net Reserves (Bcfe)(1)	
	Ethane Recovery	Ethane Rejection
Proved Reserves(2):		
Marcellus Shale	6,689	5,959
Upper Devonian Shale	44	44
Utica Shale	341	279
Total Proved Reserves	7,074	6,282
% Developed	*22%*	*23%*
% Liquids	*23%*	*9%*
Probable Reserves(2)(3):		
Marcellus Shale	14,135	11,796
Upper Devonian Shale	665	661
Utica Shale	1,958	1,582
Total Probable Reserves	16,758	14,039
% Liquids	*38%*	*19%*
Possible Reserves(2)(3):		
Marcellus Shale	989	959
Upper Devonian Shale	3,461	3,076
Utica Shale	3,843	3,393
Total Possible Reserves	8,293	7,428
% Liquids	*23%*	*10%*
PV-10 of Proved Reserves (in millions)(2)(4)	$ 4,243	$ 4,468
PV-10 of Probable Reserves (in millions)(2)(4)	$ 8,223	$ 8,868
PV-10 of Possible Reserves (in millions)(2)(4)	$ 2,210	$ 2,413

(1) Volumes and values were determined under SEC pricing using index prices for natural gas and oil of $3.43 per MMBtu and $91.65 per Bbl. These prices were then adjusted for transportation, gathering, processing, compression and other costs. For the adjusted realized prices under SEC pricing, see "Business Our Operations Reserve Data Adjusted Index Prices Used in Reserve Calculations."

(2) Our estimated proved, probable and possible reserves and PV-10 as of June 30, 2013 using SEC pricing are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent reserve engineers, DeGolyer and MacNaughton.

(3) All of our estimated probable and possible reserves are classified as undeveloped.

(4) PV-10 was prepared using SEC pricing discounted at 10% per annum, without giving effect to taxes or hedges. PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of future net cash flows, or after tax amount, because it presents the discounted future net cash flows attributable to our reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves or for proved, probable or possible reserves

Table of Contents

calculated using prices other than SEC prices. PV-10 does not take into account the effect of future taxes, and PV-10 estimates for reserve categories other than proved or for pricing sensitivities uses the relevant reserve volumes and prices, as applicable, but PV-10 is otherwise calculated using the same assumptions as those for, and in a manner consistent with, the calculation of standardized measure. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized measure of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Similarly, PV-10 estimates for price sensitivities are not adjusted for the likelihood that the relevant pricing scenario will occur, and thus they may be subject to the same issues with comparability. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved or for pricing sensitivities present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Investors should be cautioned that neither PV-10 nor standardized measure represents an estimate of the fair market value of our proved reserves. In addition, investors should be further cautioned that estimates of PV-10 of probable reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Further, because estimates of probable and possible reserve volumes and PV-10 have not been adjusted for risk due to this uncertainty of recovery, they should not be summed arithmetically with each other or with comparable estimates for proved reserves. GAAP does not prescribe any corresponding measure for PV-10 of probable reserves and possible reserves or reserves based on other than SEC prices. As a result, it is not practicable for us to reconcile these additional PV-10 measures to GAAP standardized measure. For a reconciliation of PV-10 of proved reserves based on SEC pricing to standardized measure, see " Summary Reserve, Production and Operating Data Summary Reserve Data."

Strip Pricing Sensitivity Case

	June 30, 2013	
	Estimated Net Reserves (Bcfe)(1)	
	Ethane Recovery	Ethane Rejection
Sensitivity of Estimated Proved Reserves Based on Strip Pricing(2):		
Total equivalent proved reserves	7,087	6,295
Total equivalent proved developed reserves	1,594	1,448
Percent proved developed	22%	23%
PV-10 of proved reserves (in millions)(2)(3)	$ 5,279	$ 5,644
Sensitivity of Estimated Probable Reserves Based on Strip Pricing(2)(4):		
Total equivalent probable reserves	16,776	14,057
PV-10 of probable reserves (in millions)(2)(3)	$ 9,173	$ 10,210
Sensitivity of Estimated Possible Reserves Based on Strip Pricing(2)(4):		
Total equivalent possible reserves	8,310	7,444
PV-10 of possible reserves (in millions)(2)(3)	$ 2,939	$ 3,245

(1) Volumes and values were determined under strip pricing using index prices for natural gas and oil of $3.86 per MMBtu and $87.04 per Bbl. These prices were then adjusted for transportation, gathering, processing, compression and other costs. For the adjusted realized prices under strip

Table of Contents

pricing, see "Business Our Operations Reserve Data Adjusted Index Prices Used in Reserve Calculations."

(2) Our estimated proved, probable and possible reserves and PV-10 as of June 30, 2013 based on strip pricing as of June 30, 2013 have been prepared by our internal reserve engineers, which have been audited by our independent reserve engineers, DeGolyer and MacNaughton.

(3) PV-10 was prepared using strip pricing, discounted at 10% per annum, without giving effect to taxes or hedges. PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our reserves prior to taking into account future corporate income taxes and our current tax structure. PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves or for proved, probable or possible reserves calculated using prices other than SEC prices. PV-10 does not take into account the effect of future taxes, and PV-10 estimates for reserve categories other than proved or for pricing sensitivities uses the relevant reserve volumes and prices, as applicable, but PV-10 is otherwise calculated using the same assumptions as those for, and in a manner consistent with, the calculation of standardized measure. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized measure of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Similarly, PV-10 estimates for price sensitivities are not adjusted for the likelihood that the relevant pricing scenario will occur, and thus they may be subject to the same issues with comparability. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved or for pricing sensitivities present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Investors should be cautioned that PV-10 does not represent an estimate of the fair market value of our reserves. In addition, investors should be further cautioned that estimates of PV-10 of probable reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Further, because estimates of proved and probable reserve volumes and PV-10 have not been adjusted for risk due to this uncertainty of recovery, they should not be summed arithmetically with each other or with comparable estimates for proved reserves. GAAP does not prescribe any corresponding measure for PV-10 of reserves based on other than SEC prices. As a result, it is not practicable for us to reconcile these additional PV-10 measures to GAAP standardized measure.

(4) All of our estimated probable and possible reserves are classified as undeveloped.

For more information about our reserves, including the reserves attributable to individual natural gas product types and the prices used in calculating volumes and values under each pricing scenario, see "Business Our Operations Reserve Data."

Table of Contents

Operating Data

The following table provides a summary of our net acreage and identified potential well locations as of June 30, 2013, our 2013 and 2014 projected drilling schedules based on gross wells, and our average net daily production for August 2013:

	As of June 30, 2013							
		Identified Potential Well Locations(2)				2013 Projected Drilling Schedule	Planned 2014 Drilling Schedule	Average Net Daily Production
	Net Acres(1)	Total	Proved Undeveloped	Probable	Possible	(Gross Wells)	(Gross Wells)	(MMcfe/d)
Marcellus Shale:								
Highly Rich/Condensate(3)	48,000	505	18	454	33	4	21	16
Highly Rich Gas(3)	89,000	777	116	653	8	51	54	149
Rich Gas(3)	77,000	673	276	396	1	75	75	188
Dry Gas(3)	106,000	986	277	530	179	5		192
Utica Shale	100,000	720	17	175	528	26	47	45
Upper Devonian Shale	170,000	915	7	149	759			4
Total		4,576	711	2,357	1,508	161	197	594

(1) Net acres prospective for the Upper Devonian Shale are also included among the Marcellus Shale net acres. The Upper Devonian Shale and the Marcellus Shale are stacked formations within the same geographic footprint.

(2) Our proved undeveloped, probable and possible identified potential well locations are based on specifically engineered locations to which the applicable category of reserves were attributable based on SEC pricing as of June 30, 2013. For a description of how we determine our identified potential well locations, see "Business Our Operations Reserve Data Identification of Potential Well Locations."

(3) Classifications are based on our and other operators' drilling results in the Marcellus Shale and are subject to confirmation through actual future drilling results. For definitions of "highly rich/condensate," "highly rich gas," "rich gas" and "dry gas," see the "Glossary of Natural Gas and Oil Terms" in Annex A to this prospectus.

Recent Operating Developments

Our estimated current net daily production is 640 MMcfe/d, including 11,500 Bbls/d of NGLs and oil. Our estimated current net daily production in the Marcellus Shale is 555 MMcfe/d, including 7,400 Bbls/d of NGLs and oil, and our estimated current net daily production in the Utica Shale is 85 MMcfe/d, including 4,100 Bbls/d of NGLs and oil. Current net daily production represents the average net daily production for the period from September 1, 2013 through September 25, 2013.

Midstream Infrastructure

We maintain a strong commitment to developing the necessary midstream infrastructure to support our drilling schedule and production growth. We accomplish this goal through a combination of internal asset developments and contractual relationships with third-party midstream service providers. As part of our internal developments, we have invested a significant amount of capital in building low- and high-pressure gathering lines, compression facilities and water pipeline systems. We currently own and operate 103 miles of gathering pipelines and have contracted access to an additional 94 miles of gathering pipelines in the Marcellus and Utica Shales. We also own and operate four compressor stations and have firm access to nine additional third-party compressor stations in the Appalachian

7

Table of Contents

Basin. We have additional gathering pipelines and compressor stations under construction to support our planned drilling activities in the Marcellus and Utica Shales. In the past we have monetized certain midstream infrastructure assets for a significant return on investment and redeployed the proceeds into our ongoing operations.

Through third-party contractual relationships, we have obtained committed cryogenic processing capacity for our Marcellus and Utica Shale production. For example, we have contracted with MarkWest Energy Partners, L.P., or MarkWest, to provide processing capacity as follows:

	Plant Processing Capacity (MMcf/d)	Contracted Firm Processing Capacity (MMcf/d)(1)	Anticipated Date of Completion
Marcellus Shale:			
Sherwood I	200	200	In service
Sherwood II	200	200	In service
Sherwood III	200	150	Fourth Quarter 2013
Sherwood IV	200	200	Second Quarter 2014
Marcellus Shale Total	800	750	
Utica Shale:			
Cadiz(2)	185		In service
Seneca I	200	200	Fourth Quarter 2013
Seneca II(3)	200		Fourth Quarter 2013
Seneca III(4)	200	100	First Quarter 2014
Utica Shale Total	785	300	

(1) Contracted firm capacity at the Sherwood and Seneca facilities as of the start-up date of each identified unit.

(2) Firm interim capacity of 80 MMcf/d at Cadiz will be fixed at 50 MMcf/d capacity upon start-up of the Seneca I processing complex and will terminate upon start-up of the Seneca II processing complex.

(3) We have 50 MMcf/d of interim capacity at the Seneca II processing facility until July 1, 2014.

(4) Remaining 100 MMcf/d of capacity at the Seneca III processing complex is available for commitment at our option.

Our NGL processing capacity at the Sherwood facility has been curtailed since August 2013 due to a line break in a MarkWest NGL pipeline caused by a landslide due to abnormal rainfall. Repairs and remediation to the pipeline and rights of way in the landslide impacted areas are currently underway, and MarkWest is working to return the pipeline to service, which is expected to be in October 2013. While our NGLs from that facility are being transported by truck for fractionation and sale, we estimate that our net daily production since August 2013 has been reduced by 60 to 80 MMcfe/d as a result of this line break in order to match NGL production to trucking capacity. We do not expect the temporary NGL processing capacity constraints at the Sherwood facility to have a material impact on our results of operations.

Our midstream infrastructure also includes two independent fresh water sourcing and delivery systems for well completion operations in our Marcellus and Utica Shale operating areas. These systems consist of permanent buried pipelines, temporary surface pipelines and fresh water storage facilitates, as well as pumping stations to transport the fresh water throughout the pipeline networks. Current cost estimates for both the Marcellus and Utica projects are anticipated to total $525 million through 2023. The capital expenditures are estimated to be $250 million in 2013. The water pipeline

Table of Contents

systems are expected to deliver a reliable year-round water supply, lessen water handling costs and significantly decrease water truck traffic and associated road damage on state, county and municipal roadways. It is estimated that these water pipeline systems will reduce our well completion costs by up to $600,000 per well, and we anticipate that over 30% of our 2013 completed wells and up to 90% of our 2014 completed wells will utilize these new infrastructures. Assuming a 7,000 foot horizontal well lateral, it is estimated that 1,850 water truckload trips per well completion will be eliminated from roadways.

We also have contracted 1,300,000 MMBtu/d of long-haul firm transportation or firm sales capacity on various pipelines and 20,000 Bbl/d of committed ethane takeaway capacity to accommodate our growing production and manage basis differentials.

We will continue to invest significantly in our midstream infrastructure, as it allows us to optimize our processing and takeaway capacity to support our expected rapid production growth, affords us more control over the direction and planning of our drilling schedule and has historically created significant value for our equity owners. In 2013, we estimate we will spend a total of approximately $600 million on midstream infrastructure.

In addition, we believe that our midstream assets may be well suited for a master limited partnership ("MLP") or similar structure. Accordingly, following the closing of this offering, we intend to contribute our midstream assets to Antero Resources Midstream LLC, or Antero Midstream, a subsidiary formed to hold our midstream business, and enter into commercial arrangements for midstream services with them. We will initially own all of the membership interests in Antero Midstream other than a special membership interest, which will be indirectly owned by Antero Investment. The special membership interest in Antero Midstream will provide Antero Investment with certain rights, including the right to cause an initial public offering of Antero Midstream as a MLP or similar structure. Following any such initial public offering, the special membership interest will convert into a general partner interest and incentive distribution rights in the MLP, which will allow Antero Investment to manage Antero Midstream's business and affairs. We may also seek opportunities to finance our midstream business on a stand-alone basis. See "Certain Relationships and Related Party Transactions Antero Midstream" and "Corporate Reorganization."

Business Strengths

Our objective is to build shareholder value through growth in reserves, production and cash flows by developing and expanding our portfolio of low-risk, high-return drilling locations and ensuring timely development of processing and pipeline takeaway capacity. We believe that the following strengths will allow us to successfully execute our business strategies:

- *Large, stable operated position in the core of the Marcellus and Utica Shales.* We own extensive and contiguous land positions in the core areas of two of the premier North American shale plays. We believe our approximately 329,000 net acres in the southwestern core of the Marcellus Shale and our 102,000 net acres in the Utica Shale are characterized by consistent and predictable geology. However, 92% of this acreage is currently undeveloped or does not include wells that have been drilled or completed to a point of producing commercially viable quantities. Approximately 52% of our Marcellus acreage and 20% of our Utica acreage was held by production at June 30, 2013, while an additional 27% and 78%, respectively, does not expire for five years or more. However, 48% and 80% of our natural gas leases related to our Marcellus and Utica acreage, respectively, require us to drill wells that are commercially productive by the end of the primary term, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. As of June 30, 2013, all of our total aggregate proved, probable and possible reserves were attributable to properties that we operate.

Table of Contents

Multi-year, low-risk drilling inventory. Our drilling inventory at June 30, 2013 consisted of 4,576 identified potential horizontal well locations on our existing leasehold acreage. We believe that we and other operators in the area have substantially delineated and de-risked our large contiguous acreage position in the southwestern core of the Marcellus Shale. We have drilled and completed 199 wells on our Marcellus Shale acreage with a success rate of 100%. We have drilled and completed 11 horizontal wells in the core of the Utica Shale with a 100% success rate.

Exposure to large resource of liquids-rich gas and condensate. Approximately 64% of our 4,576 identified potential horizontal well locations as of June 30, 2013 target the liquids-rich gas regions of the Marcellus and Utica Shales. The gas content of this liquids-rich gas allows for NGL processing that, coupled with the condensate, can significantly improve well economics. This exposure to a range of liquids contents allows us to optimize our drilling economics across a portfolio of liquids-rich gas locations in order to take advantage of the existing commodity price environment.

Low-cost leader. We are a low-cost leader in the U.S. Our ability to drill consistently long laterals, averaging over 7,000 lateral feet, helps us to reduce costs on a per-lateral-foot basis, which is a key competitive advantage. The contiguous nature of our leasehold and the lack of geologic complexity are critical to our ability to drill long laterals. Additionally, since June 2013, we have shortened our average frac stage lengths on many of our Marcellus Shale wells from 350 feet per stage historically to 150 to 250 feet per stage. Initial well results have shown increases in 24-hour initial production rates of 25% to 35% when compared to similar wells within the same geographic area. In addition, we estimate that the incremental costs attributable to the short stage lengths has averaged an estimated $1.5 million to $2.0 million per well. We have implemented operational efficiencies to continue lowering our costs, such as (i) pad drilling, (ii) development of an extensive water pipeline system, (iii) the use of less expensive, shallow vertical drilling rigs to drill to the kick-off point of the horizontal wellbore, (iv) the use of natural gas powered rigs and (v) our proactive approach to meeting our gathering, processing and compression infrastructure needs.

Access to committed processing, compression and takeaway capacity in the Marcellus and Utica Shales. We have contracted a total of 750 MMcf/d of processing capacity in the Marcellus Shale, 400 MMcf/d of which is currently in service. Similarly, we have 300 MMcf/d of contracted processing capacity in the Utica Shale, with the option to access additional capacity. We also have secured 1,300,000 MMBtu/d of long-haul firm transportation capacity or firm sales and have committed to 20,000 Bbl/d of ethane takeaway capacity. We believe our commitment to midstream infrastructure allows us to commercialize our production more quickly at optimal prices, making us a logical consolidator of additional acreage in our core areas.

Financial strength and flexibility. As of June 30, 2013, after giving effect to this offering and the application of the net proceeds therefrom, we expect to have approximately $1.72 billion of available borrowing capacity under our credit facility (after deducting $32 million outstanding letters of credit). After the completion of this offering and the recent increase in lender commitments under our credit facility, together with our operating cash flow and hedging program, we believe we will have the financial flexibility to pursue our currently planned 2013 and 2014 development and delineation drilling activities.

Proven and incentivized executive and technical teams. We believe our management team's experience and expertise across multiple resource plays provides a distinct competitive advantage. Our officers have an average of over 30 years of industry experience in the Rocky Mountain, Midcontinent and Appalachian operating regions and have successfully built, grown and sold two unconventional resource-focused upstream companies and one midstream company in the past 15 years. Additionally, our technical team has drilled over 450 horizontal wells in the

Table of Contents

Barnett, Woodford, Marcellus and Utica Shales over the past ten years. Our management team has a significant economic interest in us through their interest in our controlling stockholder, Antero Resources Investment LLC, or Antero Investment. Management's percentage interest in our stock held by Antero Investment may increase over time, without diluting public investors, if our stock price appreciates following this offering. We believe our management team's ability to increase their economic interest in us provides significant incentives to grow our stock price for the benefit of all stockholders.

Business Strategy

Our strategy consists of the following principal elements:

Create shareholder value through the development of our extensive drilling inventory. Since initiating our drilling program with one rig in 2009, we have invested over $3.2 billion in land and drilling in the Appalachian Basin and currently intend to use an average of 17 rigs in 2013. With 15 rigs running in the Marcellus Shale, we are currently the most active driller in the area based on information from RigData. We intend to dedicate substantially all of our $1.45 billion drilling and completion budget in 2013 to develop our liquids-rich areas. Approximately 85% of the 2013 drilling and completion budget is allocated to the Marcellus Shale, and the remaining 15% is allocated to the Utica Shale.

Enhance returns through a focus on optimizing full cycle economics. We continually monitor and adjust our drilling program with the objective of achieving the highest total returns on our portfolio of drilling opportunities. We believe that we will achieve this objective by (i) minimizing the capital costs of drilling and completing horizontal wells, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) targeting specific BTU windows within our leasehold position to optimize our hydrocarbon mix based on the existing commodity price environment, (iv) minimizing operating costs through efficient well management, and (v) pursuing infrastructure initiatives, such as the development of our extensive water pipeline system and gas gathering system.

Maximize wellhead economics by ensuring timely development of processing and pipeline takeaway capacity and the marketing of our NGLs. We expect to continue to meaningfully increase our liquids production from the NGLs, oil and condensate associated with our growing natural gas production. We endeavor to ensure that we have sufficient processing capacity in place to recover NGLs when economically desirable. We have also secured long-term firm takeaway capacity and firm sales on major pipelines that are in existence or currently under construction in our core operating areas to accommodate our growing production and to manage basis differentials. Further, we plan to maximize the value of our NGLs through processing and marketing agreements with transporters and NGL end users.

Continue growing our core acreage position through leasing and strategic acquisitions. We intend to continue identifying and acquiring additional acreage and producing assets in our core areas in the Marcellus and Utica Shales. We believe that by managing a large team of dedicated landmen, we have a competitive advantage that enables us to continue to opportunistically add acreage to our core positions. This team of landmen has allowed us to build a large, contiguous acreage position in our Marcellus and Utica Shale plays, making us the logical acreage consolidator in our core areas. We initially targeted and acquired 114,000 net acres in the Marcellus Shale in 2008, based on specific geologic and technical analysis, and have selectively built our position to approximately 329,000 net acres. We started building our targeted Utica Shale acreage position in the fourth quarter of 2011 and currently have approximately 102,000 net acres of leasehold in the core of the liquids-rich window in Ohio.

Table of Contents

Manage commodity price exposure through an active hedging program to protect our expected future cash flows. We expect to continue to maintain an active hedging program designed to mitigate volatility in commodity prices and regional basis differentials and to protect our expected future cash flows. As of June 30, 2013, we had entered into hedging contracts through December 31, 2018 covering a total of approximately 943 Bcfe of our projected natural gas and oil production at a weighted average price of $4.80 per Mcfe. These hedging contracts include hedges for the six-month period ending December 31, 2013 covering a total of approximately 84 Bcfe of our projected natural gas and oil production at a weighted average price of $4.68 per Mcfe. This hedging program has led to over $650 million in realized gains over the past five years.

Risk Factors

An investment in our common stock involves a number of risks. You should carefully consider, in addition to the other information contained in this prospectus, the risks described in "Risk Factors" before investing in our common stock. These risks could materially affect our business, financial condition and results of operations, and cause the trading price of our common stock to decline. You could lose part or all of your investment. You should bear in mind, in reviewing this prospectus, that past experience is no indication of future performance. You should read the section titled "Cautionary Statement Regarding Forward-Looking Statements" for a discussion of what types of statements are forward-looking statements, as well as the significance of such statements in the context of this prospectus.

Corporate Reorganization

Antero Resources LLC was formed in October 2009 by members of our management team and the Sponsors, as defined below. Antero Resources Appalachian Corporation, a wholly owned subsidiary of Antero Resources LLC, was formed in March 2008 and renamed Antero Resources Corporation in June 2013. Pursuant to the terms of a corporate reorganization, which will be completed immediately prior to or contemporaneously with the closing of this offering, (i) all of the outstanding interests of our existing owners in Antero Resources LLC will be exchanged for similar interests in Antero Resources Investment LLC, or Antero Investment, and (ii) Antero Resources LLC will be merged into Antero Resources Corporation.

In addition, we intend to transfer our midstream business to Antero Resources Midstream LLC, or Antero Midstream, following the closing of this offering. We will initially own all of the membership interests in Antero Midstream other than a special membership interest, which will be indirectly owned by Antero Investment. The special membership interest in Antero Midstream will provide Antero Investment with certain rights, including the right to cause an initial public offering of Antero Midstream as a MLP or similar structure. Following any such initial public offering, the special membership interest will convert into a general partner interest in the MLP, which will allow Antero Investment to manage Antero Midstream's business and affairs. Following any such initial public offering, Antero Investment will also hold incentive distribution rights in the MLP, which will represent the right to receive an increasing percentage of the MLP's quarterly cash distributions in excess of specified target distribution levels. See "Certain Relationships and Related Party Transactions Antero Midstream" and "Corporate Reorganization."

Table of Contents

The following diagram indicates our ownership structure after giving effect to our corporate reorganization and assuming no exercise of the underwriters' options to purchase additional shares. See "Corporate Reorganization" for more information regarding our corporate reorganization.

(1) Includes each of our Sponsors and certain members of our management team who have made investments in Antero Investment in exchange for investment units. For information on the entities and individuals who may be deemed to control the Sponsors and for a list of our management team (all of whom hold interests in Antero Investment), see "Principal and Selling Stockholders."

(2) Holds profits interests in Antero Investment on behalf of members of our management team and other employees. All of the membership interests in Antero Resources Employee Holdings LLC are held by our employees. The compensation committee of Antero Investment has voting and control rights over the shares held by Antero Resources Employee Holdings LLC.

(3) Represents an interest that provides Antero Investment with certain rights, including the right to cause an initial public offering of Antero Midstream as a MLP or similar structure. Following any such initial public offering, this special membership interest will convert into a general partner interest in the MLP, which will allow Antero Investment to manage Antero Midstream's business and affairs. Following any such initial public offering, Antero Investment will also hold incentive distribution rights in the MLP, which will represent the right to receive an increasing percentage of the MLP's quarterly cash distributions in excess of specified target distribution levels. See "Certain Relationships and Related Party Transactions   Antero Midstream."

Table of Contents

Our Principal Stockholders

Following the completion of this offering and our corporate reorganization, Antero Investment will directly own 88.2% of our common stock, or 86.5% if the underwriters' options to purchase additional shares from us and Antero Investment are exercised in full. Antero Investment is primarily owned by investment funds affiliated with or managed by Warburg Pincus LLC, Yorktown Partners LLC and Trilantic Capital Partners, or collectively, the Sponsors, and certain members of our management. See "Principal and Selling Stockholders" and "Corporate Reorganization Limited Liability Company Agreement of Antero Investment."

Warburg Pincus LLC is a leading global private equity firm focused on growth investing. The firm has more than $40 billion in assets under management. Its active portfolio of more than 125 companies is highly diversified by stage, sector and geography. Warburg Pincus is an experienced partner to management teams seeking to build durable companies with sustainable value. Founded in 1966, Warburg Pincus has raised 13 private equity funds which have invested more than $45 billion in over 675 companies in more than 35 countries. Since the late 1980s, Warburg Pincus has invested more than $6 billion in energy and natural resources companies around the world. In addition to Antero Resources LLC, notable energy investments for which the firm was lead and/or founding investor include Bill Barrett Corporation (NYSE: BBG), Encore Acquisition Company (NYSE: EAC, since acquired by Denbury Resources), Kosmos Energy Ltd. (NYSE: KOS), Laredo Petroleum Holdings, Inc. (NYSE: LPI), MEG Energy (TSX: MEG), Newfield Exploration (NYSE: NFX), Spinnaker Exploration (NYSE: SKE, since acquired by Norsk Hydro/Statoil) and Targa Resources (NYSE: NGLS, TRGP). The firm is headquartered in New York with offices in Amsterdam, Beijing, Frankfurt, Hong Kong, London, Luxembourg, Mumbai, Port Louis, San Francisco, Sao Paulo and Shanghai.

Yorktown Partners LLC is a private investment manager investing exclusively in the energy industry with an emphasis on North American oil and gas production, and midstream businesses. Yorktown has raised 10 private equity funds totaling over $6.5 billion. Yorktown's investors include university endowments, foundations, families, insurance companies, and other institutional investors. The firm is headquartered in New York.

Trilantic Capital Partners is a global private equity firm focused on control and significant minority investments in North America and Europe with primary investment focus in the business services, consumer, energy and financial sectors. The firm currently manages four institutional private equity funds with aggregate capital commitments of $5.7 billion. Trilantic has offices in New York, London, Guernsey and Luxembourg.

Emerging Growth Company Status

We are an "emerging growth company" as defined in the Jumpstart Our Business Startups Act, or the JOBS Act. For as long as we are an emerging growth company, unlike other public companies, we will not be required to:

- provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002;

- comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;

- comply with any new audit rules adopted by the PCAOB after April 5, 2012, unless the Securities and Exchange Commission, or the SEC, determines otherwise;

Table of Contents

- provide certain disclosure regarding executive compensation required of larger public companies; or
- obtain shareholder approval of any golden parachute payments not previously approved.

We will cease to be an "emerging growth company" upon the earliest of:

- the last day of the fiscal year in which we have $1.0 billion or more in annual revenues;
- the date on which we become a large accelerated filer;
- the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards, but we intend to irrevocably opt out of the extended transition period.

Corporate Information

Our principal executive offices are located at 1625 17th Street, Denver, Colorado 80202, and our telephone number at that address is (303) 357-7310. Our website is located at *www.anteroresources.com*. We expect to make our periodic reports and other information filed with or furnished to the SEC available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

Table of Contents

The Offering

Common stock offered by us	30,000,000 shares.
Common stock to be outstanding after the offering	254,375,000 shares (or 255,125,000 shares if the underwriters exercise their options to purchase additional shares in full).
Option to purchase additional shares from the selling stockholder	The selling stockholder has granted the underwriters a 30-day option to purchase up to an aggregate of 3,750,000 additional shares of our common stock held by the selling stockholder to cover over-allotments.
Option to purchase additional shares from us	We have granted the underwriters a 30-day option to purchase up to an aggregate of 750,000 additional shares of our common stock from us if the underwriters sell more than an aggregate of 33,750,000 shares of common stock (including the shares purchased from the selling stockholder) to cover over-allotments. Any exercise by the underwriters of their options to purchase additional shares of common stock will be made initially with respect to the 3,750,000 additional shares of common stock to be sold by the selling stockholder and then with respect to the 750,000 additional shares of common stock to be sold by us. The share amounts in each of the options assume that the public offering price is equal to $40.00 per share (the mid-point of the price range set forth on the cover of this prospectus). The aggregate number of shares that may be purchased from the selling stockholder and us by the underwriters upon the exercise of their options is not subject to adjustment based on changes in the public offering price. However, if the actual public offering price is greater than $40.00 per share, the allocation of shares among the options will be adjusted such that the number of shares that may be purchased from the selling stockholder will not result in gross proceeds of more than $150 million. Similarly, if the actual public offering price is lower than $40.00 per share, the allocation of shares among the options will be adjusted such that the number of shares that may be purchased from the selling stockholder will not result in gross proceeds of less than $150 million. In either case, the balance of the shares subject to the options will be subject to purchase from us upon the exercise thereof by the underwriters in the manner described above.
Use of proceeds	We expect to receive approximately $1.14 billion of net proceeds from the sale of the common stock offered by us after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We intend to use the net proceeds from this offering, including any proceeds received pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock from us, to repay outstanding borrowings under our credit facility.

Table of Contents

	We will not receive any of the proceeds from the sale of shares of our common stock by the selling stockholder pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock from the selling stockholder. Affiliates of certain of the underwriters are lenders under our credit facility and, accordingly, will receive a portion of the proceeds of this offering. See "Underwriting (Conflicts of Interest)."
Conflicts of interest	Because affiliates of Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Wells Fargo Securities, LLC, Credit Suisse Securities (USA) LLC, BMO Capital Markets Corp., Capital One Securities, Inc., Comerica Securities, Inc., Mitsubishi UFJ Securities (USA), Inc. and TD Securities (USA) LLC are lenders under our credit facility and will each receive more than 5% of the net proceeds of this offering due to the repayment of borrowings under the credit facility, such underwriters are deemed to have a conflict of interest within the meaning of Rule 5121 of the Financial Industry Regulatory Authority, or FINRA. Accordingly, this offering will be conducted in accordance with Rule 5121, which requires, among other things, that a "qualified independent underwriter" has participated in the preparation of, and has exercised the usual standards of "due diligence" with respect to, the registration statement and this prospectus. Jefferies LLC has agreed to act as qualified independent underwriter for this offering and to undertake the legal responsibilities and liabilities of an underwriter under the Securities Act, specifically including those inherent in Section 11 of the Securities Act. Jefferies LLC will not receive any additional fees for serving as qualified independent underwriter in connection with this offering. We have agreed to indemnify Jefferies LLC against liabilities incurred in connection with acting as a qualified independent underwriter, including liabilities under the Securities Act. See "Underwriting (Conflicts of Interest)."
Dividend policy	We do not anticipate paying any cash dividends on our common stock. In addition, our credit facility and the indentures governing our senior notes place certain restrictions on our ability to pay cash dividends.
Risk factors	You should carefully read and consider the information set forth under the heading "Risk Factors" and all other information set forth in this prospectus before deciding to invest in our common stock.
Listing and trading symbol	We have been approved to list our common stock on the New York Stock Exchange, or the NYSE, under the symbol "AR".

The information above excludes 16,534,375 shares of common stock reserved for issuance under our 2013 Long-Term Incentive Plan, or the LTIP, that we intend to adopt in connection with the completion of this offering.

Table of Contents

Summary Historical Consolidated Financial Data

The following table shows our summary historical consolidated financial data, for the periods and as of the dates indicated, for Antero Resources LLC and its subsidiaries.

The summary statement of operations data for the years ended December 31, 2010, 2011 and 2012 and the balance sheet data as of December 31, 2011 and 2012 are derived from our audited consolidated financial statements included elsewhere in this prospectus. The balance sheet data as of December 31, 2010 is derived from our audited consolidated financial statements not included in this prospectus. The summary statement of operations data for the three and six months ended June 30, 2012 and 2013 and the balance sheet data as of June 30, 2013 are derived from our unaudited consolidated financial statements included elsewhere in this prospectus. The balance sheet data as of June 30, 2012 is derived from our unaudited consolidated financial statements not included in this prospectus.

The statement of operations data for all periods presented has been recast to present the results of operations from our Piceance Basin and Arkoma Basin operations in discontinued operations. The losses on the sales of these properties are also included in discontinued operations in 2012. The results from continuing operations reflect our remaining operations in the Appalachian Basin. No part of our general and administrative expenses or interest expense was allocated to discontinued operations.

The summary historical consolidated financial data has been prepared on a consistent basis with our audited consolidated financial statements. In the opinion of management, such summary historical consolidated financial data reflects all adjustments (consisting of normal and recurring accruals) considered necessary to present our financial position for the periods presented.

The results of operations for the interim periods are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received from natural gas and oil, natural production declines, the uncertainty of exploration and development drilling results and other factors. The summary financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, "Capitalization," "Management's Discussion and

Table of Contents

Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included elsewhere herein.

	Year Ended December 31,			Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2011	2012	2012	2013	2012	2013
	(in thousands)						
Statement of operations data:							
Operating revenues:							
Natural gas, NGLs and oil production revenues	$ 47,431	$ 195,289	$ 264,982	$ 44,965	$ 191,661	$ 90,147	$ 325,056
Commodity derivative fair value gains (losses)	77,599	496,064	179,546	(6,040)	195,483	211,214	123,542
Gain on sale of assets			291,190			291,305	
Total revenues	125,030	691,353	735,718	38,925	387,144	592,666	448,598
Operating expenses:							
Lease operating expenses	1,158	4,608	6,243	1,866	1,454	2,559	2,525
Gathering, compression, processing and transportation	9,237	37,315	91,094	20,079	48,670	31,654	89,640
Production taxes	2,885	11,915	20,210	3,371	10,108	7,113	18,727
Exploration expenses	2,350	4,034	14,675	2,952	7,300	4,756	11,662
Impairment of unproved properties	6,076	4,664	12,070	1,295	4,803	1,581	6,359
Depletion, depreciation and amortization	18,522	55,716	102,026	22,321	52,589	38,431	92,953
Accretion of asset retirement obligations	11	76	101	24	267	46	531
Expenses related to acquisition of business	2,544						
General and administrative	21,952	33,342	45,284	10,473	13,567	19,646	26,284
Loss on sale of compressor station		8,700					
Total operating expenses	64,735	160,370	291,703	62,381	138,758	105,786	248,681
Operating income (loss)	60,295	530,983	444,015	(23,456)	248,386	486,880	199,917
Other expense:							
Interest expense	$ (56,463)	$ (74,404)	$ (97,510)	$ (24,223)	$ (33,468)	$ (48,593)	$ (63,396)
Interest rate derivative fair value losses	(2,677)	(94)					
Total other expense	(59,140)	(74,498)	(97,510)	(24,223)	(33,468)	(48,593)	(63,396)
Income (loss) before income taxes and discontinued operations	1,155	456,485	346,505	(47,679)	214,918	438,287	136,521
Income tax (expense) benefit	(939)	(185,297)	(121,229)	14,442	(83,725)	(183,969)	(53,325)
Income (loss) from continuing operations	216	271,188	225,276	(33,237)	131,193	254,318	83,196
Discontinued operations:							
Income (loss) from results of operations and sale of discontinued operations	228,412	121,490	(510,345)	(444,850)		(404,674)	
Net income (loss) attributable to Antero equity owners	$ 228,628	$ 392,678	$ (285,069)	$ (478,087)	$ 131,193	$ (150,356)	$ 83,196
Balance sheet data (at period end):							
Cash and cash equivalents	$ 8,988	$ 3,343	$ 18,989	$ 5,575	$ 10,867	$ 5,575	$ 10,867
Property and equipment, net	2,159,762	2,880,414	2,937,473	2,678,800	4,074,634	2,678,800	4,074,634
Total assets	2,486,287	3,788,800	3,618,793	3,586,082	4,825,148	3,586,082	4,825,148
Long-term indebtedness	652,632	1,317,330	1,444,058	1,042,172	2,418,217	1,042,172	2,418,217
Total equity	1,594,987	1,958,806	1,673,737	1,808,450	1,756,933	1,808,450	1,756,933
Other financial data:							
EBITDAX from continuing operations(1)	$ 27,824	$ 160,259	$ 284,710	$ 60,236	$ 132,608	$ 127,887	$ 251,357
EBITDAX from discontinued operations(1)	169,854	180,562	149,605	46,003		100,692	
Total EBITDAX(1)	$ 197,678	$ 340,821	$ 434,315	$ 106,239	$ 132,608	$ 228,579	$ 251,357

Net cash provided by operating activities	127,791	266,307	332,255	60,493	82,190	160,984	192,397
Net cash provided by (used in) investing activities	(230,672)	(901,249)	(463,491)	(8,372)	(630,523)	116,327	(1,178,408)
Net cash provided by (used in) financing activities	101,200	629,297	146,882	(53,039)	554,394	(275,079)	977,889
Capital expenditures(2)	423,002	929,887	1,755,430	466,570	597,938	726,262	1,236,434

(1) "EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense or interest income, derivative fair value gains or losses, excluding net cash receipts or payments on derivative instruments, taxes, impairments, depletion, depreciation, amortization, exploration expense, franchise taxes, stock compensation, business acquisition and gain or loss on sale of assets. "EBITDAX," as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows

Table of Contents

provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under our credit facility and the indentures governing our senior notes.

There are significant limitations to using EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from continuing operations to EBITDAX from continuing operations, a reconciliation of our net income (loss) from discontinued operations to

Table of Contents

EBITDAX from discontinued operations, and a reconciliation of our total EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case for the periods presented:

	Year Ended December 31,			Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2011	2012	2012	2013	2012	2013
	(in thousands)						
Net income (loss) from continuing operations	$ 216	$ 271,188	$ 225,276	$ (33,237)	$ 131,193	$ 254,318	$ 83,196
Commodity derivative fair value (gains) losses(3)	(77,599)	(496,064)	(179,546)	6,040	(195,483)	(211,214)	(123,542)
Net cash receipts on settled derivative instruments(3)	15,063	49,944	178,491	49,864	14,146	96,716	62,277
(Gain) loss on sale of assets		8,700	(291,190)			(291,305)	
Interest expense and other	59,140	74,498	97,510	24,223	33,468	48,593	63,396
Provision (benefit) for income taxes	939	185,297	121,229	(14,442)	83,725	183,969	53,325
Depreciation, depletion, amortization, and accretion	18,533	55,792	102,127	22,345	52,856	38,477	93,484
Impairment of unproved properties	6,076	4,664	12,070	1,295	4,803	1,581	6,359
Exploration expense	2,350	4,034	14,675	2,952	7,300	4,756	11,662
Other	3,106	2,206	4,068	1,196	600	1,996	1,200
EBITDAX from continuing operations	27,824	160,259	284,710	60,236	132,608	127,887	251,357
Net income (loss) from discontinued operations	228,412	121,490	(510,345)	(444,850)		(404,674)	
Commodity derivative fair value (gains) losses(3)	(166,685)	(180,130)	(46,358)	550		(65,238)	
Net cash receipts on settled derivative instruments(3)	58,650	66,654	92,166	32,647		65,874	
(Gain) loss on sale of assets	(147,559)		795,945	427,232		427,232	
Provision (benefit) for income taxes)	29,070	45,155	(272,553)	(1,717)		12,727	
Depreciation, depletion, amortization, and accretion	115,739	115,164	89,124	31,698		63,366	
Impairment of unproved properties	29,783	6,387	962	243		993	
Exploration expense	22,444	5,842	664	200		412	
EBITDAX from discontinued operations	169,854	180,562	149,605	46,003		100,692	
Total EBITDAX	$ 197,678	$ 340,821	$ 434,315	$ 106,239	$ 132,608	$ 228,579	$ 251,357
Interest expense and other	(59,140)	(74,498)	(97,510)	(24,223)	(33,468)	(48,593)	(63,396)
Exploration expense	(24,794)	(9,876)	(15,339)	(3,152)	(7,300)	(5,168)	(11,662)
Changes in current assets and current liabilities	(698)	8,309	9,887	(16,654)	(10,238)	4,040	14,723
Other	14,745	1,551	902	(1,717)	588	(17,874)	1,375
Net cash provided by operating activities	$ 127,791	$ 266,307	$ 332,255	$ 60,493	$ 82,190	$ 160,984	$ 192,397

(2) Capital expenditures as shown in this table differ from the amounts shown in the statement of cash flows in the consolidated financial statements because amounts in this table include changes in accounts payable for capital expenditures from the previous reporting period while the amounts in the statement of cash flows in the financial statements are presented on a cash basis.

(3) The adjustments for the derivative fair value (gains) losses and net cash receipts on settled commodity derivative instruments have the effect of adjusting net income (loss) from continuing operations for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses on a cash basis during the period the derivatives settled.

Summary Reserve, Production and Operating Data

Summary Reserve Data

The following table summarizes our estimated proved reserves and related standardized measure and PV-10 at December 31, 2010, 2011 and 2012 and June 30, 2013 based on SEC pricing (and not giving effect to any pricing sensitivities). See "Business Our Operations Reserve Data" for an illustration of the sensitivity of our estimated reserves and related PV-10 to changes in product price levels.

Our estimated proved reserves and PV-10 as of December 31, 2012 and June 30, 2013 are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent reserve engineers, DeGolyer and MacNaughton, or D&M. Our estimated proved reserves as of December 31, 2011 were based on evaluations prepared by our internal reserve engineers, which were audited by D&M and Ryder Scott & Company, or Ryder Scott. Over 99% and 85% of our estimated proved, probable and possible reserves as of June 30, 2013 and December 31, 2012, respectively, were audited by D&M. Over 85% of our estimated proved reserves as of December 31, 2011 were audited by D&M or Ryder Scott. Over 99% of our estimated proved reserves as of December 31, 2010 were prepared by D&M or Ryder Scott. For each period presented, the specific percentage of our estimated reserves audited or prepared (as applicable) by D&M or Ryder Scott, which we collectively refer to as our independent reserve engineers, is disclosed in the summary report of D&M or Ryder Scott incorporated by reference into, or filed as an exhibit to, the registration statement of which this prospectus forms a part. See "Business Our Operations Reserve Data Preparation of Reserve Estimates" for definitions of proved, probable and possible reserves and the technologies and economic data used in their estimation. See " Our Properties Reserves."

Our estimated proved reserves at December 31, 2010 and 2011 included reserves attributable to our Arkoma Basin and Piceance Basin assets that were sold during 2012. The information in the following table does not give any effect to or reflect our commodity hedges. In addition, the estimated proved reserves below assume ethane recovery as of December 31, 2010, 2011 and 2012 and ethane rejection as of June 30, 2013 on our liquids-rich natural gas. See "Business Our Operations Reserve Data" for more information about our reserves and pricing sensitivities.

	At December 31,			At June 30,
	2010	2011	2012	2013
Estimated proved reserves:				
Natural gas (Bcf)	2,543	3,931	3,694	5,724
NGLs (MMBbl)	104	164	203	88
Oil (MMBbl)	10	17	3	5
Total equivalent proved reserves (Bcfe)	3,231	5,017	4,929	6,282
Total equivalent proved developed reserves (Bcfe)	457	844	1,047	1,445
Percent proved developed	14%	17%	21%	23%
Total equivalent proved undeveloped reserves (Bcfe)	2,774	4,173	3,882	4,837
PV-10 of proved reserves (in millions)(1)	$ 1,466	$ 3,445	$ 1,923	$ 4,468
Standardized measure (in millions)(1)	$ 1,097	$ 2,470	$ 1,601	*

(1) PV-10 was prepared using SEC pricing, discounted at 10% per annum, without giving effect to taxes or hedges. PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of future net cash flows, or after tax amount, because it presents the discounted future net cash flows attributable to our reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique

Table of Contents

tax situation of each company, PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves or for proved, probable or possible reserves calculated using prices other than SEC prices. PV-10 does not take into account the effect of future taxes, and PV-10 estimates for reserve categories other than proved or for pricing sensitivities uses the relevant reserve volumes and prices, as applicable, but PV-10 is otherwise calculated using the same assumptions as those for, and in a manner consistent with, the calculation of standardized measure. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized measure of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Similarly, PV-10 estimates for price sensitivities are not adjusted for the likelihood that the relevant pricing scenario will occur, and thus they may be subject to the same issues with comparability. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved or for pricing sensitivities present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Investors should be cautioned that neither PV-10 nor standardized measure represents an estimate of the fair market value of our proved reserves. In addition, investors should be further cautioned that estimates of PV-10 of probable reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Further, because estimates of probable and possible reserve volumes and PV-10 have not been adjusted for risk due to this uncertainty of recovery, they should not be summed arithmetically with each other or with comparable estimates for proved reserves.

The following table sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV-10), the present value of those net cash flows after income tax (standardized measure) and the prices used in projecting future net cash flows at December 31, 2010, 2011 and 2012 and June 30, 2013:

(In millions, except per Mcf data)	**At December 31, 2010(a)**	**2011(b)**	**2012(c)**	**At June 30, 2013(d)**
				(unaudited)
Future net cash flows	$ 5,990	$ 11,470	$ 7,221	$ 14,411
Present value of future net cash flows:				
Before income tax (PV-10)	$ 1,466	$ 3,445	$ 1,923	$ 4,468
Income taxes	(369)	(975)	(322)	*
After income tax (standardized measure)	$ 1,097	$ 2,470	$ 1,601	*

(a) 12-month average prices used at December 31, 2010 were $4.18 per Mcf for the Arkoma Basin, $3.93 per Mcf for the Piceance Basin and $4.51 for the Appalachian Basin.

(b) 12-month average prices used at December 31, 2011 were $3.90 per Mcf for the Arkoma Basin, $3.84 per Mcf for the Piceance Basin and $4.16 per Mcf for the Appalachian Basin.

(c) 12-month average prices used at December 31, 2012 were $2.78 per Mcf for natural gas, $26.36 per Bbl for NGLs and $95.05 per Bbl for oil.

(d) 12-month average prices used at June 30, 2013 were $3.43 per Mcf for natural gas, $45.66 per Bbl for NGLs and $91.65 per Bbl for oil.

Table of Contents

*
With respect to PV-10 calculated as of an interim date, it is not practicable to calculate the taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Prices for 2010, 2011, 2012, and 2013 were based on 12-month unweighted average of the first-day-of-the-month pricing, without escalation. Costs are based on costs in effect for the applicable year without escalation. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reserve engineers often arrive at different estimates for the same properties.

Production, Revenues and Price History

The following table sets forth information regarding our production, our revenues and realized prices, and production costs from continuing operations in the Appalachian Basin for the years ended December 31, 2010, 2011 and 2012 and for the three and six months ended June 30, 2012 and 2013. For additional information on price calculations, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Continuing Operations Data Appalachian Basin

	Year Ended December 31,			Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2011	2012	2012	2013	2012	2013
Production data:							
Natural gas (Bcf)	11	45	87	19	39	35	73
NGLs (MBbl)			71		354		559
Oil (MBbl)		2	19	4	25	4	35
Total combined production (Bcfe)	11	45	87	19	42	35	76
Average daily combined production (MMcfe/d)	30	124	239	213	458	195	421
Average sales prices:							
Natural gas (per Mcf)	$ 4.39	$ 4.33	$ 2.99	$ 2.31	$ 4.37	$ 2.53	$ 4.05
NGLs (per Bbl)	$	$	$ 52.07	$	$ 48.70	$	$ 49.75
Oil (per Bbl)	$	$ 97.19	$ 80.34	$ 77.16	$ 85.07	$ 80.05	$ 85.36
Combined average sales prices before effects of cash settled derivatives (per Mcfe)(1)	$ 4.39	$ 4.33	$ 3.03	$ 2.32	$ 4.60	$ 2.54	$ 4.27
Combined average sales prices after effects of cash settled derivatives (per Mcfe)(1)	$ 5.78	$ 5.44	$ 5.08	$ 4.90	$ 4.94	$ 5.26	$ 5.09
Average costs per Mcfe:							
Lease operating costs	$ 0.11	$ 0.10	$ 0.07	$ 0.10	$ 0.03	$ 0.07	$ 0.03
Gathering, compression, processing and transportation	$ 0.85	$ 0.83	$ 1.04	$ 1.04	$ 1.17	$ 0.89	$ 1.18
Production taxes	$ 0.27	$ 0.26	$ 0.23	$ 0.17	$ 0.24	$ 0.20	$ 0.25
Depreciation, depletion, amortization and accretion	$ 1.71	$ 1.24	$ 1.17	$ 1.15	$ 1.27	$ 1.08	$ 1.23
General and administrative	$ 2.03	$ 0.74	$ 0.52	$ 0.54	$ 0.33	$ 0.55	$ 0.35

(1)
Average sales prices shown reflect both of the before and after effects of our cash settled derivatives. Our calculation of such effects includes realized gains or losses on cash settlements for

Table of Contents

commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges.

Discontinued Operations Data Arkoma and Piceance Basins

The table above does not include the following production or revenue from discontinued operations from the Arkoma and Piceance Basin properties which were sold in 2012:

	Year Ended December 31,		
	2010	**2011**	**2012**
Production (combined Bcfe)	36	44	35
Natural gas, NGL and oil production revenues (in millions)	$ 159	$ 197	$ 125

Table of Contents

RISK FACTORS

Investing in our common stock involves risks. You should carefully consider the information in this prospectus, including the matters addressed under "Cautionary Statement Regarding Forward-Looking Statements," and the following risks before making an investment decision. The trading price of our common stock could decline due to any of these risks, and you may lose all or part of your investment.

Risks Related to Our Business

Natural gas, NGL and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our natural gas, NGL and oil production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas, NGLs and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for natural gas, NGLs and oil;
- the price and quantity of imports of foreign natural gas, including liquefied natural gas;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Furthermore, the worldwide financial and credit crisis in recent years has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide resulting in a slowdown in economic activity and recession in parts of the world. This has reduced worldwide demand for energy and resulted in lower natural gas, NGL and oil prices.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of natural gas, NGLs and oil that we can produce economically.

If commodity prices further decrease, a significant portion of our exploitation, development and exploration projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Table of Contents

Our exploitation, development and exploration projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our natural gas reserves.

The natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development and acquisition of natural gas reserves. Our cash flow used in investing activities related to capital and exploration expenditures was approximately $1.68 billion in 2012. Our board of directors has approved a capital budget for 2013 of $2.45 billion, including $1.45 billion for drilling and completion, $400 million for leasehold acquisitions, and $600 million for the construction of water handling infrastructure and gas gathering pipelines and facilities. Our capital budget excludes acquisitions. As of June 30, 2013, we had spent approximately $1.2 billion of our 2013 capital budget. We expect to fund these capital expenditures with cash generated by operations, the proceeds of this offering, borrowings under our credit facility and possibly through additional sales of gathering assets or capital market transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our credit facility.

If our revenues or the borrowing base under our credit facility decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

Drilling for and producing natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in

Table of Contents

part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see " Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents;
- adverse weather conditions, such as blizzards, tornados, hurricanes and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in natural gas prices;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for natural gas.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our credit facility, our $525 million of 9.375% senior notes due 2017, our $400 million of 7.25% senior notes due 2019 and our $525 million of 6.00% senior notes due 2020, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the senior notes.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness, including the senior notes. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indentures governing our senior notes, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and

Table of Contents

might be required to dispose of material assets or operations to meet our debt service and other obligations. Our credit facility and the indentures governing our senior notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

The borrowing base under our credit facility is currently $2.0 billion, and lender commitments under the credit facility are $1.75 billion. Our next scheduled borrowing base redetermination is expected to occur in April 2014. In the future, we may not be able to access adequate funding under our credit facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a subsequent semi-annual borrowing base redetermination or an unwillingness or inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

We are required to pay fees to our service providers based on minimum volumes regardless of actual volume throughput.

We have various firm transportation and gas processing, gathering and compression service agreements in place, each with minimum volume delivery commitments. As of June 30, 2013, our long-term contractual obligation under these agreements was $3.0 billion. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput, which could be significant and have a material adverse effect on our results of operations. If these fees on minimum volumes are substantial, we may not be able to generate sufficient cash to cover these obligations, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our credit facility contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness), including restrictive covenants that may limit our ability to, among other things:

- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain payments;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The indentures governing our senior notes contain similar restrictive covenants. In addition, our credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indentures governing

Table of Contents

our senior notes, may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indentures governing our senior notes and our credit facility impose on us.

Our credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid, or we must pledge other natural gas properties as additional collateral after applicable grace periods. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under our credit facility. The borrowing base under our credit facility is currently $2.0 billion and lender commitments are $1.75 billion. Our next scheduled borrowing base redetermination is expected to occur in April 2014.

A breach of any covenant in our credit facility would result in a default under that agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and natural gas prices do not improve, our cash flows may be adversely impacted. Additionally, if development drilling costs increase significantly in the future, our hedged revenues may not be sufficient to cover our costs.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of June 30, 2013, we had entered into a number of hedge contracts for approximately 943 Bcfe of our projected natural gas and oil production through December 31, 2018. We are currently realizing a significant benefit from these hedge positions. For example, for the years ended December 31, 2011 and 2012, we received approximately $117 million and $271 million, respectively, in revenues pursuant to our hedges, which represented approximately 11% and 30%, respectively, of our total revenues (including revenues from discontinued operations) for such periods. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2011 and 2012 were executed at times when spot and future prices were higher than prices that we are currently able to obtain in the futures market, and the price at which we have been able to hedge future production has decreased as a result. Therefore, we expect that this benefit will decline materially over the life of the hedges, which cover decreasing volumes at declining prices through December 2018. If we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected.

Additionally, since we hedge a significant part of our estimated future production, we have fixed a significant part of our future revenue stream. For example, for the years ended December 31, 2011 and 2012, approximately 73% and 81%, respectively, of our estimated future production (including production from discontinued operations) was covered by our hedge contracts. If development drilling costs increase significantly because of inflation, increased demand for oilfield services, increased costs

Table of Contents

to comply with regulations governing our industry or other factors, future hedged revenues may not be sufficient to cover our costs.

In certain circumstances we may have to purchase commodities on the open market or make cash payments under our hedging arrangements and these payments could be significant.

If our production is less than the volume commitments under our hedging arrangements, or if natural gas or oil prices exceed the price at which we have hedged our commodities, we may be obligated to make cash payments to our hedge counterparties or purchase the volume difference at market prices, which could, in certain circumstances, be significant. As of June 30, 2013, we had entered into hedging contracts through December 31, 2018 covering a total of approximately 943 Bcfe of our projected natural gas and oil production at a weighted average price of $4.80 per Mcfe. These hedging contracts include hedges for the six-month period ending December 31, 2013 covering a total of approximately 84 Bcfe of our projected natural gas and oil production at a weighted average price of $4.68 per Mcfe. If we have to purchase additional commodities on the open market or post cash collateral to meet our obligations under such arrangements, our cash otherwise available for use in our operations would be reduced.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated natural gas reserves. We generally base the estimated discounted future net cash flows from our reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Our identified potential well locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill our potential well locations.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of

Table of Contents

water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential well locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

As of June 30, 2013, we had 4,576 identified potential horizontal well locations. As a result of the limitations described above, we may be unable to drill many of our potential well locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified potential well locations, see "Business Our Operations Identification of Potential Well Locations."

Approximately 92% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

Approximately 92% of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, 48% and 80% of our natural gas leases related to our Marcellus and Utica acreage, respectively, require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. At June 30, 2013, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

Insufficient processing or takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas and NGL prices.

The Appalachian Basin natural gas and NGL business environment has historically been characterized by periods during which production has surpassed local processing and takeaway capacity, resulting in substantial discounts in the price received. Although additional Appalachian Basin takeaway capacity has been added in 2012 and 2013, we do not believe the existing and expected capacity will be sufficient to keep pace with the increased production caused by accelerated drilling in the area. For example, we have experienced capacity constraints in the Marcellus Shale during the last several months due to delays in the completion of third-party gathering and compression infrastructure. In

Table of Contents

addition, production from almost all of our completed horizontal Utica Shale wells has been delayed for several months pending the completion of third-party high pressure gathering infrastructure.

If we are unable to secure additional gathering, compression and processing capacity and long-term firm takeaway capacity on major pipelines that are in existence or currently under construction in our core operating area to accommodate our growing production and to manage basis differentials, it could have a material adverse effect on our financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due the long history of land ownership in the area, resulting in extensive and complex chains of title. Additionally, there are claims against us alleging that certain acquired leases that are held by production are invalid due to production from the producing horizons being insufficient to hold title to the formation rights that we have purchased. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At June 30, 2013, 77% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 4.8 Tcfe of estimated proved undeveloped reserves will require an estimated $4.6 billion of development capital over the next five years. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A writedown constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Table of Contents

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, we enter into derivative instrument contracts for a significant portion of our natural gas production, including fixed-price swaps. As of June 30, 2013, we had entered into hedging contracts through December 31, 2018 covering a total of approximately 943 Bcfe of our projected natural gas and oil production at a weighted average price of $4.80 per Mcfe. These hedging contracts include hedges for the six-month period ending December 31, 2013 covering a total of approximately 84 Bcfe of our projected natural gas and oil production at a weighted average price of $4.68 per Mcfe. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates.

As of June 30, 2013, the estimated fair value of our commodity derivative contracts was approximately $593 million. Any default by the counterparties to these derivative contracts when they

Table of Contents

become due would have a material adverse effect on our financial condition and results of operations. The fair value of our commodity derivative contracts of approximately $593 million at June 30, 2013 includes the following values by bank counterparty: BNP Paribas $150 million; Credit Suisse $161 million; Wells Fargo $99 million; JP Morgan $102 million; Barclays $65 million; Deutsche Bank $11 million; Union Bank $2 million; and Toronto Dominion Bank $1 million. Additionally, contracts with Dominion Field Services account for $2 million of the fair value. The credit ratings of certain of these banks have been downgraded because of the sovereign debt crisis in Europe.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, which could also have an adverse effect on our financial condition.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables ($6 million at December 31, 2012) and the sale of our natural gas production ($47 million in receivables at December 31, 2012), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. The largest purchaser of our natural gas during the twelve months ended December 31, 2012 purchased approximately 23% of our operated production. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, regional, state and local laws and regulations relating to protection of the environment and worker health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time resulting in longer waiting periods to receive permits and other regulatory approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

For example, in March 2011, we received orders for compliance from federal regulatory agencies, including the U. S. Environmental Protection Agency, or the EPA, relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non-compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. We have responded to all pending orders and are actively cooperating with the relevant agencies. No fine or penalty relating to these matters has been proposed at this time, but we believe that these actions will result in monetary sanctions exceeding $100,000. In addition, we expect to incur additional costs to remediate these well locations in order to bring them into compliance with applicable environmental laws and regulations. We have not, however, been required to suspend our operations at these locations to date and our management team does not expect these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental and worker health and safety impacts of our operations. We have been named from time to time as a defendant in litigation related to such matters. For example, we have been named as the defendant in separate lawsuits in Colorado, West Virginia and Pennsylvania in which the plaintiffs have alleged that our oil and natural gas activities exposed them to hazardous substances and damaged their properties. The plaintiffs have requested unspecified damages and other injunctive or equitable relief. We are not yet able to estimate what our aggregate exposure for monetary or other damages resulting from these or other similar claims might be. Also, new laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting natural gas and oil related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;

- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Table of Contents

We may be limited in our ability to choose gathering operators and processing and fractionation services providers in our areas of operations pursuant to the agreements we will enter into with Antero Midstream.

Pursuant to the gas gathering and compression agreement that we intend to enter into with Antero Midstream, we will dedicate the gathering and compression of all of our current and future natural gas production in West Virginia, Ohio and Pennsylvania to Antero Midstream, so long as such production is not otherwise subject to a pre-existing dedication. Further, pursuant to the right of first offer that we intend to enter into with Antero Midstream, Antero Midstream will have a right to bid to provide certain processing and fractionation services in respect of all of our current and future gas production (as long as it is not subject to a pre-existing dedication) and will be entitled to provide such services if its bid matches or is more favorable to us than terms proposed by other parties. As a result, we will be limited in our ability to use other gathering operators in West Virginia, Ohio and Pennsylvania, even if such operators are able to offer us more favorable pricing or more efficient service. We will also be limited in our ability to use other processing and fractionation services providers in any area to the extent Antero Midstream is able to offer a competitive bid.

Properties that we decide to drill may not yield natural gas or oil in commercially viable quantities.

Properties that we decide to drill that do not yield natural gas or oil in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas or oil in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices

significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our credit facility imposes and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

Market conditions or operational impediments may hinder our access to natural gas and oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas and oil transportation arrangements may hinder our access to natural gas and oil markets or delay our production. The availability of a ready market for our natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas and oil pipeline or gathering system capacity. In addition, if natural gas or oil quality specifications for the third-party natural gas or oil pipelines with which we connect change so as to restrict our ability to transport natural gas or oil, our access to natural gas and oil markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, natural gas. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

Changes to existing or new regulations may unfavorably impact us, could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. Such potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows.

Table of Contents

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938, or NGA, exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission, or FERC, as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Domenici-Barton Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules

Table of Contents

requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act, or SDWA, over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Table of Contents

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a draft final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Competition in the natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel, including Paul M. Rady, our Chairman and Chief Executive Officer, and Glen C. Warren, Jr., our President and Chief Financial Officer, could have a material adverse effect on our business, financial condition and results of operations.

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

Natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect various wildlife. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and

Table of Contents

the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, as of June 30, 2013, outstanding borrowings and letters of credit under our credit facility were approximately $992 million, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased interest expense for that period of approximately $2.1 million and a corresponding decrease in our net income before the effects of increased interest rates on the value of our interest rate swap contracts and income taxes. In addition, an increase in interest rates could negatively impact the valuation that our midstream business would receive in an initial public offering as a MLP. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may be subject to risks in connection with acquisitions of properties.

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

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

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, 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.

Table of Contents

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

The Fiscal Year 2013 Budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress that would implement many of these proposals. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, and any such change could negatively affect our financial condition and results of operations.

In February 2013, the governor of the state of Ohio proposed a plan to enact new severance taxes in fiscal 2014 and 2015. However, the Ohio State Senate did not include a severance tax increase in the version of the budget bill that it passed on June 7, 2013. The possibility remains that the severance tax increase on horizontal wells will resurface during compromise talks on the budget.

Risks Related to the Offering and our Common Stock

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE, with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- comply with rules promulgated by the NYSE;
- continue to prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Furthermore, while we generally must comply with Section 404 of the Sarbanes Oxley Act of 2002 for our fiscal year ended December 31, 2013, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until as late as our annual report for the fiscal year ending December 31, 2018. Once it is required to do so, our independent registered

Table of Contents

public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed, operated or reviewed. Compliance with these requirements may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, an active, liquid and orderly trading market for our common stock may not develop or be maintained, and our stock price may be volatile.

Prior to this offering, our common stock was not traded on any market. An active, liquid and orderly trading market for our common stock may not develop or be maintained after this offering. Active, liquid and orderly trading markets usually result in less price volatility and more efficiency in carrying out investors' purchase and sale orders. The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The initial public offering price will be negotiated between us, the selling stockholder and representatives of the underwriters, based on numerous factors which we discuss in "Underwriting (Conflicts of Interest)," and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in this offering.

The following factors could affect our stock price:

- our operating and financial performance and drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- strategic actions by our competitors;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- sales of our common stock by us, the selling stockholder or other stockholders, or the perception that such sales may occur;
- changes in accounting principles;
- additions or departures of key management personnel;
- actions by our stockholders;
- general market conditions, including fluctuations in commodity prices; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management's attention and resources and harm our business, operating results and financial condition.

Table of Contents

Antero Investment will hold a majority of our outstanding common stock.

Immediately following the completion of this offering, Antero Investment will hold approximately 88.2% of our common stock (or 86.5% if the underwriters fully exercise their options to purchase additional shares of common stock from us and Antero Investment). Accordingly, Antero Investment will have the ability to elect all of the members of our board of directors and thereby control our management and affairs. In addition, Antero Investment will be able to determine the outcome of all matters requiring stockholder approval, including mergers, amendments to our certificate of incorporation and other material transactions and will be able to cause or prevent a change in control of our company that could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of our company. The existence of significant stockholders may also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. So long as Antero Investment continues to own a significant amount of our common stock, even if such amount represents less than 50% of the aggregate voting power, it will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests.

In addition, the limited liability company agreement of Antero Investment will provide that Antero Investment and its members will agree to vote the shares of our common stock held by Antero Investment in favor of the election of the five directors of Antero Investment to our board. See "Corporate Reorganization Limited Liability Company Agreement of Antero Investment."

Antero Investment will own a special membership interest in Antero Midstream that will provide Antero Investment with certain rights, including the right to cause an initial public offering of Antero Midstream and to prohibit our ability to sell, transfer or otherwise dispose of any portion of our midstream business or Antero Midstream without Antero Investment's consent.

Following the completion of this offering, we intend to contribute our midstream business to Antero Midstream, a newly formed limited liability company. We will own 100% of the economic interests and initially control Antero Midstream, but Antero Investment, which includes members of our management and our Sponsors, will own a special membership interest in Antero Midstream that will provide Antero Investment with certain rights, including the right to cause an initial public offering of Antero Midstream and to prohibit our ability to sell, transfer or otherwise dispose of any portion of our midstream business or Antero Midstream without Antero Investment's consent. As a result, we may not be able to manage our midstream business in a manner that will maximize its value to our stockholders. For example, we may not be able to pursue strategic dispositions of our midstream assets or determine whether to pursue an initial public offering of our midstream business when we believe it to be in the best interest of our shareholders. Following the completion of an initial public offering of Antero Midstream, Antero Investment's interest in Antero Midstream will automatically convert into a general partner interest. As a result, Antero Investment will control our current and future midstream business and may operate this business in a manner that is inconsistent with the interests of our shareholders, because those decisions will be controlled by Antero Investment and not by us. In addition, following an initial public offering of Antero Midstream, Antero Investment will have the right to receive an increasing percentage of the MLP's quarterly cash distributions in excess of specified target distribution levels. As a result, we may not receive the full economic benefit of our midstream business after an initial public offering of Antero Midstream. See "Certain Relationships and Related Party Transactions Antero Midstream Special Membership Interest."

Table of Contents

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified board of directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings; and
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Investors in this offering will experience immediate and substantial dilution of $28.61 per share.

Based on an assumed initial public offering price of $40.00 per share, purchasers of our common stock in this offering will experience an immediate and substantial dilution of $28.61 per share in the as adjusted net tangible book value per share of common stock from the initial public offering price, and our as adjusted net tangible book value as of June 30, 2013 after giving effect to this offering would be $11.39 per share. This dilution is due in large part to earlier investors having paid substantially less than the initial public offering price when they purchased their shares. See "Dilution."

We may invest or spend the proceeds of this offering in ways with which you may not agree or in ways which may not yield a return.

A portion of the net proceeds from this offering are expected to be used for general corporate purposes, including working capital. Our management will have considerable discretion in the application of the net proceeds, and you will not have the opportunity, as part of your investment decision, to assess whether the proceeds are being used appropriately. The net proceeds may be used for corporate purposes that do not increase our operating results or market value. Until the net proceeds are used, they may be placed in investments that do not produce significant income or that may lose value.

We do not intend to pay dividends on our common stock, and our credit facility and the indentures governing our senior notes place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, our credit facility and the indentures governing our senior notes place certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your common stock at a price greater than you paid for it. There is no guarantee that the price of our common stock that will prevail in the market will ever exceed the price that you pay in this offering.

Table of Contents

Future sales of our common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. After the completion of this offering, we will have 255,125,000 outstanding shares of common stock, assuming full exercise of the underwriters' options to purchase additional shares. This number includes 30,000,000 shares that we are selling in this offering, 3,750,000 shares that Antero Investment may sell in this offering if the underwriters' option to purchase additional shares from Antero Investment is fully exercised, and 750,000 shares that we may sell in this offering if the underwriters' option to purchase additional shares from us is fully exercised, which may be resold immediately in the public market. Following the completion of this offering, and assuming full exercise of the underwriters' options to purchase additional shares, Antero Investment will own 220,625,000 shares, or approximately 86.5% of our total outstanding shares, all of which are restricted from immediate resale under the federal securities laws and are subject to the lock-up agreements between the selling stockholder and the underwriters described in "Underwriting (Conflicts of Interest)," but may be sold into the market in the future.

Prior to the completion of this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of 16,534,375 shares of our common stock issued or reserved for issuance under our stock incentive plan. Subject to the satisfaction of vesting conditions, Rule 144 restrictions applicable to our affiliates and the expiration of lock-up agreements, shares registered under the registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

The underwriters of this offering may waive or release parties to the lock-up agreements entered into in connection with this offering, which could adversely affect the price of our common stock.

Antero Investment and our directors and executive officers have entered into lock-up agreements with respect to their common stock, pursuant to which they are subject to certain resale restrictions for a period of 180 days following the effectiveness date of the registration statement of which this prospectus forms a part. Barclays Capital Inc., at any time and without notice, may release all or any portion of the common stock subject to the foregoing lock-up agreements. If the restrictions under the lock-up agreements are waived, then common stock will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital.

We expect to be a "controlled company" within the meaning of the NYSE rules and, as a result, will qualify for and could rely on exemptions from certain corporate governance requirements.

Upon completion of this offering, Antero Investment will control a majority of the combined voting power of all classes of our outstanding voting stock, and we expect to be a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;

Table of Contents

- the nominating and governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual performance evaluation of the nominating and governance and compensation committees.

These requirements will not apply to us as long as we remain a controlled company. Following this offering, we may utilize some or all of these exemptions. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. See "Management."

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

We are classified as an "emerging growth company" under the JOBS Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes Oxley Act of 2002, (2) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise, (4) provide certain disclosure regarding executive compensation required of larger public companies or (5) hold stockholder advisory votes on executive compensation.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this prospectus includes "forward-looking statements." All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Risk Factors" included in this prospectus. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas, NGLs and oil prices;
- timing and amount of future production of natural gas, NGLs and oil;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, NGLs and oil;
- leasehold or business acquisitions;
- costs of developing our properties and conducting our gathering and other midstream operations;
- general economic conditions;

- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this prospectus that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under "Risk Factors" in this prospectus.

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs, and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this prospectus occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this prospectus are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this prospectus.

Table of Contents

USE OF PROCEEDS

We expect to receive approximately $1.14 billion of net proceeds from the sale of the common stock offered by us after deducting underwriting discounts and commissions and estimated offering expenses payable by us.

We intend to use the net proceeds from this offering, including any proceeds received pursuant to any exercise by the underwriters of their option to purchase additional shares of common stock from us, to repay outstanding borrowings under our credit facility. As of September 27, 2013, we had approximately $1.49 billion of outstanding borrowings and letters of credit under our credit facility, which matures in May 2016 and bears interest at a variable rate, which was approximately 2.1% as of June 30, 2013. The borrowings to be repaid were incurred primarily for our drilling and development program and for general corporate purposes. While we currently do not have plans to immediately borrow additional amounts under the credit facility, we may at any time reborrow amounts repaid under the credit facility.

A $1.00 increase or decrease in the assumed initial public offering price of $40.00 per share would cause the net proceeds from this offering, after deducting the underwriting discounts and commissions and estimated offering expenses payable to us, to increase or decrease, respectively, by approximately $28.65 million. If the proceeds increase due to a higher initial public offering price, we would use the additional net proceeds to fund a portion of our drilling and development program. If the proceeds decrease due to a lower initial public offering price, then we would reduce by a corresponding amount the net proceeds directed to repay outstanding borrowings under our credit facility.

We will not receive any of the proceeds from the sale of shares of our common stock by the selling stockholder pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock from the selling stockholder. Any exercise by the underwriters of their options to purchase additional shares of common stock will be made initially with respect to the 3,750,000 additional shares of common stock to be sold by the selling stockholder and then with respect to the 750,000 additional shares of common stock to be sold by us. We will pay all expenses related to this offering, other than underwriting discounts and commissions related to the shares sold by the selling stockholder.

Affiliates of certain of the underwriters are lenders under our credit facility and will receive a portion of the proceeds of this offering. Accordingly, this offering is being made in compliance with Rule 5121 of the FINRA. See "Underwriting (Conflicts of Interest)."

DIVIDEND POLICY

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the growth of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon then-existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant. In addition, our credit facility and the indentures governing our senior notes place certain restrictions on our ability to pay cash dividends.

Table of Contents

CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of June 30, 2013:

- on an actual basis; and
- as adjusted to give effect to the transactions described under "Corporate Reorganization" which will be completed immediately prior to or contemporaneously with the closing of this offering and the application of the net proceeds as set forth under "Use of Proceeds."

This table should be read in conjunction with, and is qualified in its entirety by reference to, "Use of Proceeds" and our historical audited and unaudited consolidated financial statements and the accompanying notes appearing elsewhere in this prospectus.

	As of June 30, 2013	
	Actual	As Adjusted
	(in thousands)	
Cash and cash equivalents	$ 10,867	$ 191,867
Indebtedness:		
Senior secured revolving credit facility(1)	960,000	
9.375% senior notes due 2017	525,000	525,000
7.25% senior notes due 2019	400,000	400,000
6.00% senior notes due 2020	525,000	525,000
9.00% senior note due 2013	25,000	25,000
Net unamortized premium	8,217	8,217
Total indebtedness	2,443,217	1,483,217
Equity:		
Members' equity	1,460,947	
Common stock, $1.00 par value (actual); $0.01 par value (as adjusted); 1,000,000,000 shares authorized (as adjusted); 254,375,000 shares issued and outstanding (as adjusted)		2,544
Preferred stock, $0.01 par value; 50,000,000 shares authorized (as adjusted); no shares issued and outstanding (as adjusted)		
Additional paid in capital(2)		2,861,403
Accumulated earnings	295,986	33,986
Total equity	1,756,933	2,897,933
Total capitalization	$ 4,200,150	$ 4,381,150

(1) As of September 27, 2013, the outstanding balance under our credit facility was approximately $1.46 billion. In addition, as of September 27, 2013, we had outstanding letters of credit under our credit facility of approximately $32 million. As of September 27, 2013, after giving effect to the application of the net proceeds of this offering, we would have had approximately $1.4 billion of available borrowing capacity under our credit facility.

(2) In connection with our corporate reorganization, we expect to recognize non-cash stock compensation expense of approximately $262.0 million at the time of the offering. In addition, approximately $147.5 million of stock compensation expense will be amortized over the remaining service period. The stock compensation expense recognized in the statement of operations will be offset by a capital contribution from Antero Investment; therefore, the stock compensation charge will have no effect on total equity. The

estimated stock compensation charge that we will recognize at the time of the offering is reflected in the as adjusted amounts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Corporate Reorganization."

Table of Contents

DILUTION

Purchasers of the common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. Our net tangible book value as of June 30, 2013, after giving effect to the transactions described under "Corporate Reorganization," was $1.76 billion, or $7.83 per share. Pro forma net tangible book value per share is determined by dividing our pro forma tangible net worth (tangible assets less total liabilities) by the total number of outstanding shares of common stock that will be outstanding immediately prior to the closing of this offering including giving effect to our corporate reorganization. After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated net proceeds (after deducting estimated underwriting discounts and commissions and estimated offering expenses), our adjusted pro forma net tangible book value as of June 30, 2013 would have been approximately $2.90 billion, or $11.39 per share. This represents an immediate increase in the net tangible book value of $3.56 per share to our existing stockholders and an immediate dilution (i.e., the difference between the offering price and the adjusted pro forma net tangible book value after this offering) to new investors purchasing shares in this offering of $28.61 per share. The following table illustrates the per share dilution to new investors purchasing shares in this offering:

Assumed initial public offering price per share		$ 40.00
Pro forma net tangible book value per share as of June 30, 2013 (after giving effect to our corporate reorganization)	$ 7.83	
Increase per share attributable to new investors in this offering	3.56	
As adjusted pro forma net tangible book value per share after giving effect to our corporate reorganization and this offering		11.39
Dilution in pro forma net tangible book value per share to new investors in this offering		$ 28.61

The following table summarizes, on an adjusted pro forma basis as of June 30, 2013, the total number of shares of common stock owned by existing stockholders and to be owned by new investors, the total consideration paid, and the average price per share paid by our existing stockholders and to be paid by new investors in this offering at $40.00, the midpoint of the range of the initial public offering price set forth on the cover page of this prospectus, calculated before deduction of estimated underwriting discounts and commissions:

	Shares Acquired		Total Consideration		Average Price
	Number	Percent	Amount	Percent	Per Share
			(in thousands)		
Existing stockholders(1)	224,375,000	88.2%	$ 1,756,933	59.4%	$ 7.83
New investors in this offering	30,000,000	11.8	1,200,000	40.6	
Total	254,375,000	100.0%	$ 2,956,933	100.0%	$ 40.00

(1) The number of shares disclosed for the existing stockholders includes 3,750,000 shares that may be sold by the selling stockholder in this offering pursuant to any exercise of the underwriters' option to purchase additional shares of common stock.

A $1.00 increase or decrease in the assumed initial public offering price of $40.00 per share, which is the midpoint of the range set forth on the cover page of this prospectus, would increase or decrease our as adjusted pro forma net tangible book value as of June 30, 2013 by approximately $28.65 million, the as adjusted pro forma net tangible book value per share after this offering by $0.11 per share and the dilution in pro forma as adjusted net tangible book value per share to new investors in this offering by $0.89 per share, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting the estimated underwriting discounts and commissions and estimated offering expenses payable by us.

Table of Contents

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table shows our selected historical consolidated financial data, for the periods and as of the dates indicated, for Antero Resources LLC and its subsidiaries.

The selected statement of operations data for the years ended December 31, 2010, 2011 and 2012 and the balance sheet data as of December 31, 2011 and 2012 are derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected statement of operations data for the years ended December 31, 2008 and 2009 and the balance sheet data as of December 31, 2008, 2009, and 2010 are derived from our audited consolidated financial statements not included in this prospectus. The selected statement of operations data for the three and six months ended June 30, 2012 and 2013 and the balance sheet data as of June 30, 2013 are derived from our unaudited consolidated financial statements included elsewhere in this prospectus. The balance sheet data as of June 30, 2012 is derived from our unaudited consolidated financial statements not included in this prospectus.

The statement of operations data for all periods presented has been recast to present the results of operations from our Piceance Basin and Arkoma Basin operations in discontinued operations. The losses on the sales of these properties are also included in discontinued operations in 2012. The results from continuing operations reflect our remaining operations in the Appalachian Basin. No part of our general and administrative expenses or interest expense was allocated to discontinued operations.

The selected historical consolidated financial data has been prepared on a consistent basis with our audited consolidated financial statements. In the opinion of management, such selected historical consolidated financial data reflects all adjustments (consisting of normal and recurring accruals) considered necessary to present our financial position for the periods presented.

The results of operations for the interim periods are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received from natural gas and oil, natural production declines, the uncertainty of exploration and development drilling results and other factors. The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, "Capitalization," "Management's Discussion and

Table of Contents

Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included elsewhere herein.

	Year Ended December 31,					Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands, except ratios)	**2008**	**2009**	**2010**	**2011**	**2012**	**2012**	**2013**	**2012**	**2013**
Statement of operations data:									
Operating revenues:									
Natural gas sales	$	$ 2,252	$ 47,392	$ 195,116	$ 259,743	$ 44,688	$ 172,332	$ 89,822	$ 294,278
NGL sales					3,719		17,244		27,816
Oil sales			39	173	1,520	277	2,085	325	2,962
Commodity derivative fair value gains (losses)		3,910	77,599	496,064	179,546	(6,040)	195,483	211,214	123,542
Gain on sale of assets					291,190			291,305	
Total revenues		6,162	125,030	691,353	735,718	38,925	387,144	592,666	448,598
Operating expenses:									
Lease operating expenses		28	1,158	4,608	6,243	1,866	1,454	2,559	2,525
Gathering, compression, processing and transportation		421	9,237	37,315	91,094	20,079	48,670	31,654	89,640
Production taxes		128	2,885	11,915	20,210	3,371	10,108	7,113	18,727
Exploration expenses		2,095	2,350	4,034	14,675	2,952	7,300	4,756	11,662
Impairment of unproved properties		100	6,076	4,664	12,070	1,295	4,803	1,581	6,359
Depletion, depreciation and amortization	391	1,706	18,522	55,716	102,026	22,321	52,589	38,431	92,953
Accretion of asset retirement obligations			11	76	101	24	267	46	531
Expenses related to acquisition of business			2,544						
General and administrative	16,171	20,843	21,952	33,342	45,284	10,473	13,567	19,646	26,284
Loss on sale of compressor station				8,700					
Total operating expenses	16,562	25,321	64,735	160,370	291,703	62,381	138,758	105,786	248,681
Operating income (loss)	(16,562)	(19,159)	60,295	530,983	444,015	(23,456)	248,386	486,880	199,917
Other expense:									
Interest expense	$ (37,594)	$ (36,053)	$ (56,463)	$ (74,404)	$ (97,510)	$ (24,223)	$ (33,468)	$ (48,593)	$ (63,396)
Interest rate derivative fair value losses	(15,245)	(4,985)	(2,677)	(94)					
Total other expense	(52,839)	(41,038)	(59,140)	(74,498)	(97,510)	(24,223)	(33,468)	(48,593)	(63,396)
Income (loss) before income taxes and discontinued operations	(69,401)	(60,197)	1,155	456,485	346,505	(47,679)	214,918	438,287	136,521
Income tax (expense) benefit	26,520		(939)	(185,297)	(121,229)	14,442	(83,725)	(183,969)	(53,325)
Income (loss) from continuing operations	(42,881)	(60,197)	216	271,188	225,276	(33,237)	131,193	254,318	83,196
Discontinued operations:									
Income (loss) from results of operations and sale of discontinued operations	126,837	(45,972)	228,412	121,490	(510,345)	(444,850)		(404,674)	
Net income (loss) attributable to Antero equity owners	$ (83,956)	$ (106,169)	$ 228,628	$ 392,678	$ (285,069)	$ (478,087)	$ 131,193	$ (150,356)	$ 83,196
Balance sheet data (at period end):									
Cash and cash equivalents	$ 38,969	$ 10,669	$ 8,988	$ 3,343	$ 18,989	$ 5,575	$ 10,867	$ 5,575	$ 10,867
Other current assets	165,199	84,175	147,917	330,299	255,617	296,776	317,038	296,776	317,038

Total current assets	204,168	94,844	156,905	333,642	274,606	302,351	327,905	302,351	327,905
Natural gas properties, at cost (successful efforts method):									
Unproved properties	649,605	596,694	737,358	834,255	1,243,237	984,105	1,366,023	984,105	1,366,023
Producing properties	1,148,306	1,340,827	1,762,206	2,497,306	1,689,132	1,925,216	2,629,529	1,925,216	2,629,529
Gathering systems and facilities	179,836	185,688	85,404	142,241	168,930	113,270	334,096	113,270	334,096
Other property and equipment	3,113	3,302	5,975	8,314	9,517	9,615	11,282	9,615	11,282
	1,980,860	2,126,511	2,590,943	3,482,116	3,110,816	3,032,206	4,340,930	3,032,206	4,340,930
Less accumulated depletion, depreciation and amortization	(183,145)	(322,992)	(431,181)	(601,702)	(173,343)	(353,406)	(266,296)	(353,406)	(266,296)
Property and equipment, net	1,797,715	1,803,519	2,159,762	2,880,414	2,937,473	2,678,800	4,074,634	2,678,800	4,074,634
Other assets	27,084	38,203	169,620	574,744	406,714	604,931	422,609	604,931	422,609
Total assets	$2,028,967	1,936,566	$2,486,287	$3,788,800	$3,618,793	$3,586,082	$4,825,148	$3,586,082	$4,825,148
Current liabilities	$ 208,209	$ 112,493	$ 152,483	$ 255,058	$ 376,296	$ 311,766	$ 477,531	$ 311,766	$ 477,531
Long-term indebtedness	622,734	515,499	652,632	1,317,330	1,444,058	1,042,172	2,418,217	1,042,172	2,418,217
Other long-term liabilities	20,469	9,467	86,185	257,606	124,702	423,694	172,467	423,694	172,467
Total equity	1,177,555	1,299,107	1,594,987	1,958,806	1,673,737	1,808,450	1,756,933	1,808,450	1,756,933
Total liabilities and equity	$2,028,967	$1,936,566	$2,486,287	$3,788,800	$3,618,793	$3,586,082	$4,825,148	$3,586,082	$4,825,148

Table of Contents

(in thousands, except ratios)	Year Ended December 31, 2008	2009	2010	2011	2012	Three Months Ended June 30, 2012	2013	Six Months Ended June 30, 2012	2013
Other financial data:									
EBITDAX from continuing operations(1)	$ (15,288)	$ (15,857)	$ 27,824	$ 160,259	$ 284,710	$ 60,236	$ 132,608	$ 127,887	$ 251,357
EBITDAX from discontinued operations(1)	223,801	217,127	169,854	180,562	149,605	46,003		100,692	
Total EBITDAX(1)	$ 208,513	$ 201,270	$ 197,678	$ 340,821	$ 434,315	$ 106,239	$ 132,608	$ 228,579	$ 251,357
Net cash provided by operating activities	157,515	149,307	127,791	266,307	332,255	60,493	82,190	160,984	192,397
Net cash provided by (used in) investing activities	(1,004,010)	(281,899)	(230,672)	(901,249)	(463,491)	(8,372)	(630,523)	116,327	(1,178,408)
Net cash provided by (used in) financing activities	874,350	104,292	101,200	629,297	146,882	(53,039)	554,394	(275,079)	977,889
Capital expenditures(2)	1,041,748	203,454	423,002	929,887	1,755,430	466,570	597,938	726,262	1,236,434

(1) "EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense or interest income, derivative fair value gains or losses, excluding net cash receipts or payments on derivative instruments, taxes, impairments, depletion, depreciation, amortization, exploration expense, franchise taxes, stock compensation, business acquisition and gain or loss on sale of assets. "EBITDAX," as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under our credit facility and the indentures governing our senior notes.

There are significant limitations to using EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from continuing operations to EBITDAX from continuing operations, a reconciliation of our net income (loss) from discontinued operations to

Table of Contents

EBITDAX from discontinued operations, and a reconciliation of our total EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case for the periods presented:

(in thousands)	Year Ended December 31, 2008	2009	2010	2011	2012	Three Months Ended June 30, 2012	2013	Six Months Ended June 30, 2012	2013
Net income (loss) from continuing operations	$ (42,881)	$ (60,197)	$ 216	$ 271,188	$ 225,276	$ (33,237)	$ 131,193	$ 254,318	$ 83,196
Commodity derivative fair value (gains) losses(3)		(3,910)	(77,599)	(496,064)	(179,546)	6,040	(195,483)	(211,214)	(123,542)
Net cash receipts on settled derivative instruments(3)			15,063	49,944	178,491	49,864	14,146	96,716	62,277
(Gain) loss on sale of assets				8,700	(291,190)			(291,305)	
Interest expense and other	52,839	41,038	59,140	74,498	97,510	24,223	33,468	48,593	63,396
Provision (benefit) for income taxes	(26,520)		939	185,297	121,229	(14,442)	83,725	183,969	53,325
Depreciation, depletion, amortization, and accretion	391	1,706	18,533	55,792	102,127	22,345	52,856	38,477	93,484
Impairment of unproved properties		100	6,076	4,664	12,070	1,295	4,803	1,581	6,359
Exploration expense		2,095	2,350	4,034	14,675	2,952	7,300	4,756	11,662
Other	883	3,311	3,106	2,206	4,068	1,196	600	1,996	1,200
EBITDAX from continuing operations	(15,288)	(15,857)	27,824	160,259	284,710	60,236	132,608	127,887	251,357
Net income (loss) from discontinued operations	126,837	(45,972)	228,412	121,490	(510,345)	(444,850)		(404,674)	
Commodity derivative fair value (gains) losses(3)	(116,354)	(51,455)	(166,685)	(180,130)	(46,358)	550		(65,238)	
Net cash receipts on settled derivative instruments(3)	26,053	116,550	58,650	66,654	92,166	32,647		65,874	
(Gain) loss on sale of assets			(147,559)		795,945	427,232		427,232	
Provision (benefit) for income taxes)	29,549	(2,605)	29,070	45,155	(272,553)	(1,717)		12,727	
Depreciation, depletion, amortization, and accretion	124,606	138,372	115,739	115,164	89,124	31,698		63,366	
Impairment of unproved properties	10,112	54,104	29,783	6,387	962	243		993	
Exploration expense	22,998	8,133	22,444	5,842	664	200		412	
EBITDAX from discontinued operations	223,801	217,127	169,854	180,562	149,605	46,003		100,692	
Total EBITDAX	$ 208,513	$ 201,270	$ 197,678	$ 340,821	$ 434,315	$ 106,239	$ 132,608	$ 228,579	$ 251,357
Interest expense and other	(52,839)	(41,038)	(59,140)	(74,498)	(97,510)	(24,223)	(33,468)	(48,593)	(63,396)
Exploration expense	(22,998)	(10,228)	(24,794)	(9,876)	(15,339)	(3,152)	(7,300)	(5,168)	(11,662)
Changes in current assets and current liabilities	4,047	(2,648)	(698)	8,309	9,887	(16,654)	(10,238)	4,040	14,723
Other	20,792	1,951	14,745	1,551	902	(1,717)	588	(17,874)	1,375
Net cash provided by operating activities	$ 157,515	$ 149,307	$ 127,791	$ 266,307	$ 332,255	$ 60,493	$ 82,190	$ 160,984	$ 192,397

(2) Capital expenditures as shown in this table differ from the amounts shown in the statement of cash flows in the consolidated financial statements because amounts in this table include changes in accounts payable for capital expenditures from the previous reporting period while the amounts in the statement of cash flows in the financial statements are presented on a cash basis.

(3) The adjustments for the derivative fair value (gains) losses and net cash receipts on settled commodity derivative instruments have the effect of adjusting net income (loss) from continuing operations for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses on a cash basis during the period the derivatives settled.

Table of Contents

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes included elsewhere in this prospectus. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in natural gas, NGL and oil prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements." Also, see the risk factors and other cautionary statements described under the heading "Risk Factors" included elsewhere in this prospectus. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Our Company

We are an independent oil and natural gas company engaged in the exploitation, development and acquisition of natural gas, NGLs and oil properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. We are focused on creating shareholder value through the development of our large portfolio of repeatable, low cost, liquids-rich drilling opportunities in two of the premier North American shale plays. We currently hold approximately 329,000 net acres in the southwestern core of the Marcellus Shale and approximately 102,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 170,000 net acres of our Marcellus Shale leasehold are prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on a portion of our Marcellus Shale acreage in West Virginia that we believe is prospective for the dry gas Utica Shale. As of June 30, 2013, our estimated proved, probable and possible reserves were 6.3 Tcfe, 14.0 Tcfe and 7.4 Tcfe, respectively, and our proved reserves were 23% proved developed and 91% natural gas, assuming ethane rejection. As of June 30, 2013, our drilling inventory consisted of 4,576 identified potential horizontal well locations, approximately 64% of which are liquids-rich drilling opportunities.

The statement of operations data for all periods presented in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" has been recast to present the results of operations from our Arkoma Basin and Piceance operations in discontinued operations.

Source of Our Revenues

Our revenues are derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our production revenues derive entirely from the continental United States. During 2012 our revenues from both continuing and discontinued operations were comprised of approximately 85% from the production and sale of natural gas and 15% from the production and sale of NGLs and oil. Natural gas, NGL, and oil prices are inherently volatile and are influenced by many factors outside of our control. Substantially all of our production is derived from natural gas wells which also produce NGLs and limited quantities of oil. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a significant portion of our natural gas production. We currently use fixed price natural gas swaps in which we receive a fixed price for future production in exchange for a payment of the variable market price received at the time future production is sold. At the end of each period we estimate the fair value of these swaps and, because we have not elected hedge accounting, we recognize the changes in the fair value of unsettled commodity derivative instruments in earnings at the end of each accounting period. We expect continued volatility in the fair value of these swaps.

Principal Components of Our Cost Structure

Lease operating expenses. These are the day to day operating costs incurred to maintain production of our natural gas, NGLs, and oil. Such costs include produced water recycling, pumping, maintenance, repairs, and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services.

Gathering, compression, processing and transportation. These are costs incurred to bring natural gas, NGLs, and oil to the market. Such costs include the costs to operate and maintain our low and high pressure gathering and compression systems as well as fees paid to third parties who operate low- and high-pressure gathering systems that transport our gas. They also include costs to process and extract NGLs from our produced gas and to transport our NGLs and oil to market. We often enter into fixed price long-term contracts that secure transportation and processing capacity that may include minimum volume commitments, the cost for which is included in these expenses.

Production taxes. Production taxes consist of severance and ad valorem taxes and are paid on produced natural gas, NGLs, and oil based on a percentage of market prices (not hedged prices) and at fixed per unit rates established by federal, state or local taxing authorities.

Exploration expense. These are geological and geophysical costs and include seismic costs, costs of unsuccessful exploratory dry holes and unsuccessful leasing efforts.

Impairment of unproved and proved properties. These costs include unproved property impairment and costs associated with lease expirations. We could record impairment charges for proved properties if the carrying value were to exceed estimated future cash flows. Through June 30, 2013, we have not recorded any impairment for proved properties.

Depreciation, depletion and amortization. Depreciation, depletion and amortization, or DD&A, includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs, and oil. As a "successful efforts" company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and allocate these costs to each unit of production using the units of production method.

General and administrative expense. These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance expenses.

Interest expense. We finance a portion of our working capital requirements and acquisitions with borrowings under our credit facility. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. At June 30, 2013, we also had a fixed interest rate of 9.375% on senior notes having a principal balance of $525 million, a fixed interest rate of 7.25% on senior notes having a principal balance of $400 million, and a fixed interest rate of 6.00% on senior notes having a principal balance of $525 million. We expect to continue to incur significant interest expense as we continue to grow.

Income tax expense. Through December 31, 2011, each of our operating entities filed separate federal and state income tax returns; therefore, our provision for income taxes through that date consisted of the sum of our income tax provisions for each of the operating entities. In October

59

Table of Contents

2012, we completed a reorganization of our legal structure by contributing all of the outstanding shares owned by Antero Resources LLC in each of the Antero Arkoma, Antero Piceance and Antero Pipeline corporations to Antero Appalachian. Antero Arkoma, Antero Piceance, and Antero Pipeline were first converted to limited liability companies and then liquidated as part of the reorganization. As a result, for income tax purposes, the operations subsequent to the reorganizations and tax attributes of Arkoma, Piceance and Pipeline are now combined with Antero Appalachian for tax reporting purposes. Our subsidiaries are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs and the deferral of unrealized commodity hedge gains for tax purposes until they are realized. We do pay some state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We have generated net operating loss carryforwards that expire at various dates from 2024 through 2032. We have recognized the value of these net operating losses to the extent of our deferred tax liabilities. We recorded valuation allowances for deferred tax assets at December 31, 2012 of approximately $48 million primarily for capital loss and state loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or estimates of future taxable income are reduced.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more likely than not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements included unrecognized benefits at December 31, 2012 and June 30, 2013 of $15 million that, if recognized, would result in a reduction of other long-term liabilities and an increase in noncurrent deferred tax liabilities. No impact to our 2012 effective tax rate would result from the recognition of the tax benefits. As of June 30, 2013, we have accrued $0.4 million of interest expense on unrecognized tax benefits.

Corporate Reorganization

The limited liability company agreement of Antero Investment to be adopted in connection with the closing of this offering provides a mechanism by which the shares of our common stock to be allocated amongst the members of Antero Investment, including Antero Resources Employee Holdings LLC, or Employee Holdings, will be determined. As a result, the satisfaction of all performance, market, and service conditions relative to the membership interests awards held by Employee Holdings will be probable. Accordingly, we will recognize approximately $262.0 million in a non-cash charge for stock compensation expense for the estimated fair value of the prospective distributions to Employee Holdings at the closing of this offering and approximately an additional $147.5 million over the remaining service period. The charge will not have a dilutive effect on the pro forma as adjusted net tangible book value per share to new investors in this offering.

We will retain an independent valuation firm to estimate the fair value of the shares to be distributed in satisfaction of the profits interests which will be charged to expense at the closing of this offering and over the remaining service period, respectively. Because consideration for the membership interests awards will be deemed given by Antero Investment, the charge to expense will be accounted for as a capital contribution by Antero Investment to us and credited to additional paid-in capital.

Table of Contents

Results of Operations

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2013

The following table sets forth selected operating data (as recast for discontinued operations) for the three months ended June 30, 2012 compared to the three months ended June 30, 2013:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2013	Amount of Increase (Decrease)	Percent Change
	(in thousands, except per unit and production data)			
Operating revenues:				
Natural gas sales	$ 44,688	$ 172,332	$ 127,644	286%
NGL sales		17,244	17,244	*
Oil sales	277	2,085	1,808	653%
Commodity derivative fair value gains (losses)	(6,040)	195,483	201,523	*
Total operating revenues	38,925	387,144	348,219	895%
Operating expenses:				
Lease operating expense	1,866	1,454	(412)	(22)%
Gathering, compression, processing and transportation	20,079	48,670	28,591	142%
Production taxes	3,371	10,108	6,737	200%
Exploration expenses	2,952	7,300	4,348	147%
Impairment of unproved properties	1,295	4,803	3,508	271%
Depletion, depreciation, and amortization	22,321	52,589	30,268	136%
Accretion of asset retirement obligations	24	267	243	1,013%
General and administrative	10,473	13,567	3,094	30%
Total operating expenses	62,381	138,758	76,377	122%
Operating income (loss)	(23,456)	248,386	271,842	*
Interest expense	(24,223)	(33,468)	(9,245)	38%
Income (loss) before income taxes and discontinued operations	(47,679)	214,918	262,597	*
Income tax benefit (expense)	14,442	(83,725)	(98,167)	*
Income (loss) from continuing operations	(33,237)	131,193	164,430	*
Loss from discontinued operations	(444,850)		444,850	*
Net income (loss) attributable to Antero members	$ (478,087)	$ 131,193	$ 609,280	*
EBITDAX from continuing operations(1)	$ 60,236	$ 132,608	$ 72,372	120%
Total EBITDAX(1)	$ 106,239	$ 132,608	$ 26,369	25%
Production data:				
Natural gas (Bcf)	19	39	20	104%
NGLs (MBbl)		354	354	*
Oil (MBbl)	4	25	21	585%
Combined (Bcfe)	19	42	23	115%
Daily combined production (MMcfe/d)	213	458	245	115%
Average prices before effects of cash settled derivatives(2):				
Natural gas (per Mcf)	$ 2.31	$ 4.37	$ 2.06	89%
NGLs (per Bbl)	$	$ 48.70	$ *	*
Oil (per Bbl)	$ 77.16	$ 85.07	$ 7.91	10%
Combined (per Mcfe)	$ 2.32	$ 4.60	$ 2.28	98%
Average realized prices after effects of cash settled derivatives(2):				
Natural gas (per Mcf)	$ 4.89	$ 4.74	$ (0.15)	(3)%
NGls (per Bbl)	$	$ 48.70	$ 48.70	*

Oil (per Bbl)	$	77.16	$	80.70	$	3.54	5%
Combined (per Mcfe)	$	4.90	$	4.94	$	0.04	1%
Average costs (per Mcfe):							
Lease operating costs	$	0.10	$	0.03	$	(0.07)	(70)%
Gathering, compression, processing and transportation	$	1.04	$	1.17	$	0.13	13%
Production taxes	$	0.17	$	0.24	$	0.07	41%
Depletion, depreciation, amortization, and accretion	$	1.15	$	1.27	$	0.12	10%
General and administrative	$	0.54	$	0.33	$	(0.21)	(39)%

(1) See " Non-GAAP Financial Measure" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX from continuing and discontinued operations to net income (loss) from continuing and discontinued operations attributable to Antero members and to cash flow provided by operating activities.

(2) Average prices shown in the table reflect the sales prices we received before and after giving effect to our realized commodity hedging transactions. Our calculation of such after-effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges for accounting purposes. Oil and NGL production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

* Not meaningful or applicable

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $45 million from continuing operations for the three months ended June 30, 2012 to $192 million for the three months ended June 30, 2013, an increase of $147 million, or 326%. Our production increased by 115% over that same period, from 19 Bcfe from continuing operations for the three months ended June 30, 2012 to 42 Bcfe for the three months ended June 30, 2013. Net equivalent prices before the effects of realized hedge gains increased from $2.32 per Mcfe for the three months ended June 30, 2012 to $4.60 for the three months ended June 30, 2013, an increase of 98%. Increased production volumes accounted for an approximate $52 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price), and commodity price increases accounted for an approximate $95 million increase in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from additional producing wells as a result of the ongoing Appalachian Basin drilling program. Additionally, natural gas prices were significantly higher than the depressed price levels during the previous year's quarter, increasing from an average of $2.31 during the three months ended June 30, 2012 to $4.37 during the three months ended June 30, 2013.

Commodity derivative fair value gains (losses). To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our results of operations.

For the three months ended June 30, 2012 and 2013, our hedges resulted in derivative fair value gains (losses) of $(6) million and $195 million, respectively. The derivative fair value gains included $50 million and $14 million of cash settlements received on derivatives for the three months ended June 30, 2012 and 2013, respectively.

Lease operating expenses. Lease operating expenses decreased by 22% from the three months ended June 30, 2012 to the three months ended June 30, 2013 from $1.9 million to $1.5 million due primarily to workover expenses of $1.1 million incurred in the previous year that did not recur in 2013. On a per unit basis, lease operating expenses decreased by 70%, from $0.10 per Mcfe for the three months ended June 30, 2012 to $0.03 for the three months ended June 30, 2013, primarily because of the decrease in workover expenses. Excluding the 2012 workover expenses, lease operating expenses per Mcfe increased from $0.02 in 2012 to $0.03 in 2013.

Gathering, compression, processing and transportation expense. Gathering, compression, processing, and transportation expense increased from $20 million for the three months ended June 30, 2012 to $49 million for the three months ended June 30, 2013, primarily due to an increase in production volumes, increased costs on firm transportation commitments and processing charges incurred in the 2013 period but not the 2012 period. On a per unit basis, gathering, compression, processing and transportation expense increased by $0.13 per Mcfe, or 13%, for the three months ended June 30, 2013 compared to the three months ended June 30, 2012. We began processing natural gas in order to extract NGLs in October 2012 and this resulted in an increase of $0.13 per Mcfe. Increased gathering and compression charges of $0.15 per Mcfe were offset by a reduction of per unit firm transportation fees of $0.15 per unit. Firm transportation charges increased by $3 million for the three months ended

Table of Contents

June 30, 2013 compared to the prior year period, but decreased on a per unit basis by $0.15 per Mcfe as total production increased from the prior year period. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity on major pipelines.

Production taxes. Total production taxes increased by approximately $7 million for the three months ended June 30, 2013 compared to the three months ended June 30, 2012, primarily as a result of increased production. On a per unit basis, production taxes increased from $0.17 to $0.24 per Mcfe. Production taxes as a percentage of natural gas, NGL, and oil revenues were 7.5% and 5.3% for the three months ended June 30, 2012 and 2013, respectively. Production taxes declined as a percent of production revenues because of higher per unit sales prices during the three months ended June 30, 2013 compared to the three months ended June 30, 2012 and the impact of this on the West Virginia production tax liability.

Exploration expense. Exploration expense increased from $3 million for the three months ended June 30, 2012 to $7 million for the three months ended June 30, 2013 primarily due to an increase in the cost of unsuccessful lease acquisition efforts as we increased the number of third-party lease brokers contracted in the Appalachian Basin.

Impairment of unproved properties. Impairment of unproved properties was approximately $1 million for the three months ended June 30, 2012 compared to $5 million for the three months ended June 30, 2013. The increase in impairment charges was due to an increase in expiring acreage and ongoing evaluation of our undeveloped Marcellus acreage. We charge impairment expense for expired or soon-to-be-expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks, expected well economics, or future plans to develop the acreage.

DD&A. DD&A increased from $22 million for the three months ended June 30, 2012 to $53 million for the three months ended June 30, 2013, primarily because of increased production. DD&A per Mcfe increased by 10% from $1.15 per Mcfe during the three months ended June 30, 2012 to $1.27 per Mcfe during the three months ended June 30, 2013 as a result of increased depreciation on gathering systems and facilities and increased proved property costs subject to depletion.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the three months ended June 30, 2012 or 2013 for proved properties.

General and administrative expense. General and administrative expense increased from $10 million for the three months ended June 30, 2012 to $14 million for the three months ended June 30, 2013, primarily as a result of increased staffing levels and related salary and benefits expenses and increases in legal and other general corporate expenses, all of which resulted from our growth in production levels and development activities. On a per unit basis, general and administrative expense decreased by 39%, from $0.54 per Mcfe during the three months ended June 30, 2012 to $0.33 per Mcfe during the three months ended June 30, 2013, primarily due to a 115% increase in production during that time. We had 132 employees as of June 30, 2012 and 184 employees as of June 30, 2013.

Interest expense. Interest expense increased from $24 million for the three months ended June 30, 2012 to $33 million for the three months ended June 30, 2013, primarily due to the issuance of a total of $525 million of 6.00% senior notes due 2020 during the fourth quarter of 2012 and the first quarter of 2013. Interest expense includes approximately $2 million of non-cash amortization of deferred financing costs for both the three months ended June 30, 2012 and 2013.

Table of Contents

Income tax benefit (expense). Income tax benefit (expense) changed from a deferred benefit of $14 million for the three months ended June 30, 2012 to a deferred expense of $84 million for the three months ended June 30, 2013. The deferred benefit in 2012 resulted primarily from unrealized commodity derivative losses. The deferred expense in 2013 resulted from pre-tax income of $215 million which included $181 million of unrealized commodity derivative gains.

At December 31, 2012, we had approximately $1.0 billion of U.S. federal net operating loss carryforwards, or NOLs, and approximately $1.3 billion of state NOLs, which expire starting in 2024 through 2032. From time to time, there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more likely than not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. Our financial statements included unrecognized benefits at June 30, 2013 of $15 million that, if recognized, would result in a reduction of other long-term liabilities and an increase in noncurrent deferred tax liabilities. As of June 30, 2013, we had accrued approximately $0.4 million of interest on unrecognized tax benefits.

Loss from discontinued operations. The loss from discontinued operations for the three months ended June 30, 2012 resulted from the recasting of the revenues and direct expenses from the Piceance and Arkoma properties, which were sold during 2012, as discontinued operations. The loss from discontinued operations for the three months ended June 30, 2012 includes a $427 million loss on the sale of the Arkoma properties. We did not reclassify any general and administrative expenses or interest expense from continuing operations to discontinued operations.

Table of Contents

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2013

The following table sets forth selected operating data (as recast for discontinued operations) for the six months ended June 30, 2012 compared to the six months ended June 30, 2013:

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2013	Amount of Increase (Decrease)	Percent Change
	(in thousands, except per unit and production data)			
Operating revenues:				
Natural gas sales	$ 89,822	$ 294,278	$ 204,456	228%
NGL sales		27,816	27,816	*
Oil sales	325	2,962	2,637	811%
Commodity derivative fair value gains	211,214	123,542	(87,672)	(42)%
Gain on sale of gathering system	291,305		(291,305)	*
Total operating revenues	592,666	448,598	(144,068)	(24)%
Operating expenses:				
Lease operating expense	2,559	2,525	(34)	(1)%
Gathering, compression, processing, and transportation	31,654	89,640	57,986	183%
Production taxes	7,113	18,727	11,614	163%
Exploration expenses	4,756	11,662	6,906	145%
Impairment of unproved properties	1,581	6,359	4,778	302%
Depletion, depreciation, and amortization	38,431	92,953	54,522	142%
Accretion of asset retirement obligations	46	531	485	1,054%
General and administrative	19,646	26,284	6,638	34%
Total operating expenses	105,786	248,681	142,895	135%
Operating income (loss)	486,880	199,917	(286,963)	(59)%
Interest expense	(48,593)	(63,396)	(14,803)	30%
Income before income taxes and discontinued operations	438,287	136,521	(301,766)	(69)%
Income tax expense	(183,969)	(53,325)	130,644	(71)%
Income from continuing operations	254,318	83,196	(171,122)	(67)%
Loss from discontinued operations	(404,674)		404,674	*
Net income (loss) attributable to Antero members	$ (150,356)	$ 83,196	$ 233,552	*
EBITDAX from continuing operations(1)	$ 127,887	$ 251,357	$ 123,470	97%
Total EBITDAX(1)	$ 228,579	$ 251,357	$ 22,778	10%
Production data:				
Natural gas (Bcf)	35	73	38	105%
NGLs (MBbl)		559	559	*
Oil (MBbl)	4	35	31	764%
Combined (Bcfe)	35	76	41	116%
Daily combined production (MMcfe/d)	195	421	226	116%
Average prices before effects of cash settled derivatives(2):				
Natural gas (per Mcf)	$ 2.53	$ 4.05	$ 1.52	60%
NGLs (per Bbl)	$	$ 49.75	$ 49.75	*
Oil (per Bbl)	$ 80.05	$ 85.36	$ 5.31	7%
Combined (per Mcfe)	$ 2.54	$ 4.27	$ 1.73	68%
Average realized prices after effects of cash settled derivatives(2):				
Natural gas (per Mcf)	$ 5.26	$ 4.91	$ (0.35)	(7)%
NGls (per Bbl)	$	$ 49.75	$ 49.75	*
Oil (per Bbl)	$ 80.05	$ 79.14	$ (0.91)	(1)%
Combined (per Mcfe)	$ 5.26	$ 5.09	$ (0.17)	(3)%

Average costs (per Mcfe):							
Lease operating costs	$	0.07	$	0.03	$	(0.04)	(57)%
Gathering, compression, and transportation	$	0.89	$	1.18	$	0.29	33%
Production taxes	$	0.20	$	0.25	$	0.05	25%
Depletion, depreciation, amortization, and accretion	$	1.08	$	1.23	$	0.15	14%
General and administrative	$	0.55	$	0.35	$	(0.20)	(36)%

(1) See " Non-GAAP Financial Measure" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX from continuing and discontinued operations to net income (loss) from continuing and discontinued operations attributable to Antero members and to cash flow provided by operating activities.

Table of Contents

(2) Average prices shown in the table reflect the sales prices we received before and after giving effect to our realized commodity hedging transactions. Our calculation of such after-effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges for accounting purposes. Oil and NGL production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

* Not meaningful or applicable

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $90 million from continuing operations for the six months ended June 30, 2012 to $325 million for the six months ended June 30, 2013, an increase of $235 million, or 261%. Our production increased by 116% over that same period, from 35 Bcfe from continuing operations for the six months ended June 30, 2012 to 76 Bcfe for the six months ended June 30, 2013. Net equivalent prices before the effects of realized hedge gains increased from $2.54 per Mcfe for the six months ended June 30, 2012 to $4.27 for the six months ended June 30, 2013, an increase of 68%. Increased production volumes accounted for an approximate $103 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price), and commodity price increases accounted for an approximate $132 million increase in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from additional producing wells as a result of the ongoing Appalachian Basin drilling program. Additionally, natural gas prices were significantly higher than the depressed price levels during the previous year period, increasing from an average of $2.53 during the six months ended June 30, 2012 to $4.05 during the six months ended June 30, 2013.

Commodity derivative fair value gains. For the six months ended June 30, 2012 and 2013, our hedges resulted in derivative fair value gains of $211 million and $124 million, respectively. The derivative fair value gains included $97 million and $62 million of cash settlements received on derivatives for the six months ended June 30, 2012 and 2013, respectively.

Lease operating expenses. Lease operating expenses were approximately $3 million during each of the six month periods ending June 30, 2012 and 2013. On a per unit basis, lease operating expenses decreased by 57%, from $0.07 per Mcfe for the six months ended June 30, 2012 to $0.03 for the six months ended June 30, 2013, primarily because of a decrease in workover expenses and because, during the early stages of production for Appalachian Basin wells, operating and maintenance expenses are low and initial production rates are higher than for wells that have been producing for longer periods of time. Excluding the effect of workover expenses in 2012, lease operating expenses on a per unit basis were $0.03 per Mcfe during both the six months ended June 30, 2012 and 2013.

Gathering, compression, processing and transportation expense. Gathering, compression, processing and transportation expense increased from $32 million for the six months ended June 30, 2012 to $90 million for the six months ended June 30, 2013, primarily due to an increase in production volumes, increased costs on firm transportation commitments, and processing charges incurred in the 2013 period but not the 2012 period. On a per unit basis, gathering, compression, and transportation expense increased by $0.29 per Mcfe, or 33%, for the six months ended June 30, 2013 compared to the six months ended June 30, 2012. In October 2012, we began processing natural gas in order to extract NGLs and the resulting processing charges accounted for $0.14 per Mcfe of the increase in gathering, compression, processing and transportation expense from the six months ended June 30, 2012 to June 30, 2013. Increased gathering, fuel, and compression charges accounted for $0.26 per Mcfe of the year-over-year increase and were offset by a $0.12 per Mcfe decrease in firm transportation charges. Firm transportation charges increased by $7 million for the six months ended June 30, 2013 compared to the prior year period, but decreased by $0.12 per Mcfe as total production increased from the prior year period. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity on major pipelines.

Table of Contents

Production taxes. Total production taxes increased by approximately $12 million for the six months ended June 30, 2013 compared to the six months ended June 30, 2012, primarily as a result of increased production. On a per unit basis, production taxes increased from $0.20 to $0.25 per Mcfe. Production taxes as a percentage of natural gas, NGL, and oil revenues were 7.9% and 5.8% for the six months ended June 30, 2012 and 2013, respectively. Production taxes declined as a percent of production revenues because of higher per unit sales prices during the six months ended June 30, 2013 compared to the six months ended June 30, 2012 and the impact of this on the West Virginia production tax liability.

Exploration expense. Exploration expense increased from $5 million for the six months ended June 30, 2012 to $12 million for the six months ended June 30, 2013 primarily due to an increase in the cost of unsuccessful lease acquisition efforts as we have increased the number of third-party lease brokers contracted in the Appalachian Basin.

Impairment of unproved properties. Impairment of unproved properties was approximately $2 million for the six months ended June 30, 2012 compared to $6 million for the six months ended June 30, 2013. The increase in impairment charges was due to an increase in expiring acreage and ongoing evaluation of our undeveloped Marcellus acreage. We charge impairment expense for expired or soon-to-be-expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks, expected well economics, or future plans to develop the acreage.

DD&A. DD&A increased from $38 million for the six months ended June 30, 2012 to $93 million for the six months ended June 30, 2013, primarily because of increased production. DD&A per Mcfe increased by 14% from $1.08 per Mcfe during the six months ended June 30, 2012 to $1.23 per Mcfe during the six months ended June 30, 2013 as a result of increased depreciation on gathering systems and facilities and increased proved property costs subject to depletion.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the six months ended June 30, 2012 or 2013 for proved properties.

General and administrative expense. General and administrative expense increased from $20 million for the six months ended June 30, 2012 to $26 million for the six months ended June 30, 2013, primarily as a result of increased staffing levels and related salary and benefits expenses and increases in legal and other general corporate expenses, all of which resulted from our growth in production levels and development activities. On a per unit basis, general and administrative expense decreased by 36%, from $0.55 per Mcfe during the six months ended June 30, 2012 to $0.35 per Mcfe during the six months ended June 30, 2013, primarily due to a 116% increase in production during that time. We had 150 employees as of December 31, 2012 and 184 employees as of June 30, 2013.

Interest expense. Interest expense increased from $49 million for the six months ended June 30, 2012 to $63 million for the six months ended June 30, 2013, primarily due to the issuance of a total of $525 million of 6.00% senior notes due 2020 during the fourth quarter of 2012 and the first quarter of 2013. Interest expense includes approximately $2 million and $3 million of non-cash amortization of deferred financing costs for the six months ended June 30, 2012 and 2013, respectively.

Income tax benefit (expense). Income tax expense of $184 million and $53 million for the six months ended June 30, 2012 and 2013, respectively, relates to pre-tax income from continuing operations of $438 million and $137 million for the six months ended June 30, 2012 and 2013, respectively. Pre-tax income includes unrealized commodity derivative gains of $114 million and

Table of Contents

$61 million during the six months ended June 30, 2012 and 2013, respectively, and a $291 million gain on the sale of assets in 2012.

At December 31, 2012, we had approximately $1.0 billion of U.S. federal NOLs and approximately $1.3 billion of state NOLs, which expire starting in 2024 through 2032. From time to time, there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more likely than not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. Our financial statements included unrecognized benefits at June 30, 2013 of $15 million that, if recognized, would result in a reduction of other long-term liabilities and an increase in noncurrent deferred tax liabilities. As of June 30, 2013, we have accrued approximately $0.4 million of interest on unrecognized tax benefits.

Loss from discontinued operations. The loss from discontinued operations for the six months ended June 30, 2012 resulted from the recasting of the revenues and direct expenses from the Piceance and Arkoma properties, which were sold during 2012, as discontinued operations. The loss from discontinued operations of $405 million for the six months ended June 30, 2012 includes a $427 million loss on the sale of the Arkoma properties. We did not reclassify any general and administrative expenses or interest expense from continuing operations to discontinued operations.

Table of Contents

Year Ended December 31, 2011 Compared to Year Ended December 31, 2012

The following table sets forth selected operating data (as recast for discontinued operations) for the year ended December 31, 2011 compared to the year ended December 31, 2012:

(in thousands, except per unit data)	Year Ended December 31, 2011	Year Ended December 31, 2012	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 195,116	$ 259,743	$ 64,627	33%
NGL sales		3,719	3,719	*
Oil sales	173	1,520	1,347	779%
Commodity derivative fair value gains	496,064	179,546	(316,518)	(63)%
Gain on sale of assets		291,190	291,190	*
Total operating revenues	691,353	735,718	44,365	6%
Operating expenses:				
Lease operating expenses	4,608	6,243	1,635	35%
Gathering, compression, processing and transportation	37,315	91,094	53,779	144%
Production taxes	11,915	20,210	8,295	70%
Exploration	4,034	14,675	10,641	264%
Impairment of unproved properties expense	4,664	12,070	7,406	159%
Depletion, depreciation and amortization	55,716	102,026	46,310	83%
Accretion of asset retirement obligations	76	101	25	33%
General and administrative expense	33,342	45,284	11,942	36%
Loss on sale of compressor station	8,700		(8,700)	*
Total operating expenses	160,370	291,703	131,333	82%
Operating income	530,983	444,015	(86,968)	(16)%
Other income expense:				
Interest expense	$ (74,404)	$ (97,510)	$ (23,106)	31%
Interest rate derivative fair value loss	(94)		94	*
Total other expense	(74,498)	(97,510)	(23,012)	31%
Income before income taxes and discontinued operations	456,485	346,505	(109,980)	(24)%
Income taxes expense	(185,297)	(121,229)	(64,068)	(35)%
Income from continuing operations	271,188	225,276	(45,912)	(17)%
Income (loss) from discontinued operations	121,490	(510,345)	(631,835)	*
Net income (loss) attributable to Antero equity owners	$ 392,678	$ (285,069)	$ (677,747)	(173)%
EBITDAX from continuing operations(1)	$ 160,259	$ 284,710	$ 124,451	78%
EBITDAX from discontinued operations(1)	180,562	149,605	(30,957)	(17)%
Total EBITDAX(1)	$ 340,821	$ 434,315	$ 93,494	27%
Production data:				
Natural gas (Bcf)	45	87	42	93%
NGLs (MBbl)		71	71	*
Oil (MBbl)	2	19	17	963%
Combined (Bcfe)	45	87	42	93%
Daily combined production (MMcfe/d)	124	239	115	93%
Average sales prices before effects of cash settled derivatives(2):				
Natural gas (per Mcf)	$ 4.33	2.99	(1.34)	(31)%
NGLs (per Bbl)		52.07	52.07	*

Oil (per Bbl)	$	97.19	80.34	(16.85)	(17)%
Combined (per Mcfe)	$	4.33	3.03	(1.30)	(30)%
Average realized sales prices after effects of cash settled derivatives(2):					
Natural gas (per Mcf)	$	5.44	5.05	(0.39)	(7)%
NGLs (per Bbl)			52.07	52.07	*
Oil (per Bbl)	$	97.19	80.34	(16.85)	(17)%
Combined (per Mcfe)	$	5.44	5.08	(0.36)	(7)%
Average costs (per Mcfe):					
Lease operating costs	$	0.10	0.07	(0.03)	(30)%
Gathering compression and transportation	$	0.83	1.04	0.21	25%
Production taxes	$	0.26	0.23	(0.03)	(12)%
Depletion depreciation amortization and accretion	$	1.24	1.17	(0.07)	(6)%
General and administrative	$	0.74	0.52	(0.22)	(30)%

(1) See "Selected Historical Consolidated Financial Data" included elsewhere in this prospectus for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

(2) Average sales prices shown in the table reflect both of the before and after effects of our cash settled derivatives. Our calculation of such after effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGL production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

* Not meaningful or applicable.

Natural gas, NGLs, and oil sales. Combined revenues from production of natural gas, NGLs, and oil increased from $195 million for the year ended December 31, 2011 to $265 million for the year ended December 31, 2012, an increase of $70 million, or 36%. Our production increased by 94% from 45 Bcfe in 2011 to 87 Bcfe in 2012. Increased production volumes increased revenues by $183 million, or 93%, (calculated as the increase in year-to-year volumes times the prior year average price), and combined commodity price decreases accounted for a $113 million, or 58% decrease in revenues (calculated as the decrease in year-to-year average combined price times current year production volumes).

Commodity derivative fair value gains. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our results of operations. For the years ended December 31, 2011 and 2012, our hedges resulted in derivative fair value gains of $496 million and $180 million, respectively. The derivative fair value gains included $50 million and $178 million of cash settlements received on derivatives for the years ended December 31, 2011 and 2012, respectively.

Gain on sale of Appalachian gathering assets. On March 26, 2012, we closed the sale of a portion of our Marcellus Shale gathering system assets along with exclusive rights to gather and compress our gas for a 20-year period within an area of dedication, or AOD, to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together, "Crestwood") for $375 million (subject to customary purchase price adjustments). The sale included approximately 25 miles of low pressure pipeline systems and gathering rights on 104,000 net acres held by us within a 250,000 acre AOD and had an effective date of January 1, 2012. Other third-party producers will also have access to the Crestwood system. During the first seven years of the contract, we are committed to deliver minimum volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies. We can earn up to an additional $40 million of sale proceeds if we meet certain volume thresholds over the first three years of the contract. Crestwood is obligated to incur all future capital costs to build out gathering systems and compression facilities within the AOD to connect our wells as it executes its drilling program and has assumed the various risks and rewards of the system build-out and operations. Because we have not retained the substantial risks and rewards of ownership associated with the gathering rights and systems transferred to Crestwood, it has recognized a gain on the sale of the gathering system and gathering rights of approximately $291 million.

Lease operating expenses. Lease operating expenses increased from $5 million for the year ended December 31, 2011 to $6 million in 2012, primarily as a result of increased production. On a per-Mcfe basis, lease operating expenses decreased by 30%, from $0.10 per Mcfe in 2011 to $0.07 per Mcfe in 2012 primarily because of costs increasing at a lower rate than production. Because our Appalachian Basin properties are in a relatively early stage of production, production rates are high and per unit lease operating expenses are low. Lease operating expenses are expected to increase on a per unit basis as the properties mature and production declines on a per well basis.

Gathering, compression, processing and transportation expense. Gathering, compression, processing and transportation expense increased from $37 million for the year ended December 31, 2011 to $91 million in 2012. The increase in these expenses resulted from the increase in production, increased firm transportation commitments, and increases in third-party compression and gathering expenses as we move to outsource some of our compression and gathering activities. On a per-Mcfe basis, total gathering, compression, processing and transportation expenses increased from $0.83 per Mcfe for 2011 to $1.04 in 2012.

Table of Contents

Production tax expense. Total production taxes increased from $12 million for the year ended December 31, 2011 to $20 million for the year ended December 31, 2012, primarily as a result of increased production. Production taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging were 6.1% for the year ended December 31, 2011 compared to 7.6% for the year ended December 31, 2012. West Virginia ad valorem taxes, which are based on the value of oil and gas reserves, accounted for the increase in the ratio of production tax expense to revenues as we increased our Appalachian reserves.

Exploration expense. Exploration expense increased from $4 million for the year ended December 31, 2011 to $15 million for the year ended December 31, 2012 primarily because of an increase in the cost of unsuccessful lease acquisition efforts as we materially increased the number of third-party lease brokers providing services to us in the Appalachian Basin.

Impairment of unproved properties. Impairment of unproved properties was approximately $5 million for the year ended December 31, 2011 compared to $12 million for the year ended December 31, 2012. The increase in impairment charges was due to an increase in expiring acreage and ongoing evaluation of our undeveloped Marcellus acreage. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

DD&A. DD&A increased from $56 million for the year ended December 31, 2011 to $102 million for the year ended December 31, 2012, an increase of $46 million, as a result of increased production in 2012 compared to 2011. DD&A per Mcfe decreased 6%, from $1.24 per Mcfe during 2011 to $1.17 per Mcfe during 2012 as a result of the increased proved reserves in 2012.

We evaluate the impairment of our proved natural gas, NGLs, and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the years ended December 31, 2011 or 2012 for proved properties. As of December 31, 2012, no significant exploratory well costs had been deferred for over one year pending proved reserves determination.

General and administrative expense. General and administrative expense increased from $33 million for the year ended December 31, 2011 to $45 million during 2012, an increase of $12 million. The increase is due to increased costs related to salaries, employee benefits, contract personnel and other general business expenses required to support the growth of our capital expenditure program and production levels. The number of our full-time employees grew from 107 at December 31, 2011 to 150 at December 31, 2012. On a per-Mcfe basis, general and administrative expense decreased by 30%, from $0.74 per Mcfe during the year ended December 31, 2011 to $0.52 per Mcfe during 2012 primarily due to a 93% growth in production. No portion of general and administrative expenses was allocated to discontinued operations as we do not expect any reduction of such expenses as a result of the sale of the Arkoma and Piceance properties. When all discontinued operations are included, general and administrative expenses were $0.37 per Mcfe for both 2011 and 2012.

Interest expense and interest rate derivative fair value loss. Interest expense increased from $74 million for the year ended December 31, 2011 to $98 million for the year ended December 31, 2012, an increase of $24 million as a result of an increase in the amount of senior notes outstanding during 2012 compared to during 2011.

Table of Contents

Income tax expense. For each tax year-end through December 31, 2011, Antero Resources LLC and each of its subsidiaries filed separate federal and state income tax returns. Antero Resources LLC is a partnership for income tax purposes and therefore is not subject to federal or state income taxes. The tax on the income of Antero Resources LLC is borne by its individual members through the allocation of taxable income. In October 2012, we completed a reorganization of its legal structure by contributing all of the outstanding shares owned by Antero Resources LLC in each of the Antero Arkoma, Antero Piceance, and Antero Pipeline corporations to Antero Appalachian. Antero Arkoma, Antero Piceance, and Antero Pipeline were first converted to limited liability companies and then liquidated as part of the reorganization. As a result, for income tax purposes, the operations subsequent to the liquidations and tax attributes of Arkoma, Piceance and Pipeline are now combined with Antero Appalachian for tax reporting purposes.

Income tax expense related to continuing operations was $121 million in 2012 compared to $185 million in 2011. Although we have accrued $15 million at December 31, 2012 for unrecognized tax benefits, no taxes are due at the end of either December 31, 2011 or 2012. We have not generated current taxable income in either the current or prior years, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. At December 31, 2012, we had approximately $1.0 billion of U.S. Federal net operating loss carryforwards, or NOLs, and approximately $1.3 billion of state NOLs, which expire starting in 2024 and through 2032. At December 31, 2012, we recorded valuation allowances of approximately $48 million for deferred tax assets primarily related to capital loss and state loss carryforwards. From time to time there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements include unrecognized benefits at December 31, 2012 of $15 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. No impact to our 2012 effective tax rate would result. As of December 31, 2012, no interest or penalties have been accrued on unrecognized tax benefits. We had no unrecognized tax benefits at December 31, 2010 or 2011.

Income (loss) from discontinued operations. Income (loss) from discontinued operations includes the results of operations from the Arkoma Basin and Piceance Basin operations (including revenues and direct operating expenses and allocated income tax expense, but not general and administrative or interest expenses) and, in 2012, the loss on the sale of these assets. A detailed analysis of these operations is included in note 3 to the consolidated financial statements included elsewhere in this prospectus. Income (loss) from discontinued operations decreased from income of $121 million in 2011 to a loss of $510 million in 2012, primarily as a result of the loss on the sale of the properties of $796 million and a $273 million tax benefit from the loss.

Table of Contents

Year Ended December 31, 2010 Compared to Year Ended December 31, 2011

The following table sets forth selected operating data (as recast for discontinued operations) for the year ended December 31, 2010 compared to the year ended December 31, 2011:

(in thousands, except per unit data)	Year Ended December 31, 2010	2011	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 47,392	$ 195,116	$ 147,724	312%
Oil sales	39	173	134	344%
Commodity derivative fair value gains	77,599	496,064	418,465	539%
Total operating revenues	125,030	691,353	566,323	453%
Operating expenses:				
Lease operating expenses	1,158	4,608	3,450	298%
Gathering, compression, processing and transportation	9,237	37,315	28,078	304%
Production taxes	2,885	11,915	9,030	313%
Exploration expenses	2,350	4,034	1,684	72%
Impairment of unproved properties	6,076	4,664	(1,412)	(23)%
Depletion, depreciation and amortization	18,522	55,716	37,194	201%
Accretion of asset retirement obligations	11	76	65	591%
Expenses related to acquisition of business	2,544		(2,544)	*
General and administrative	21,952	33,342	11,390	52%
Loss on sale of compressor station		8,700	8,700	*
Total operating expenses	64,735	160,370	95,635	148%
Operating income	60,295	530,983	470,688	781%
Other expense:				
Interest expense	(56,463)	(74,404)	17,941	32%
Interest rate derivative fair value losses	(2,677)	(94)	(2,583)	(96)%
Total other expense	(59,140)	(74,498)	15,358	26%
Income before income taxes and discontinued operations	1,155	456,485	455,330	*
Income tax expense	(939)	(185,297)	(184,358)	*
Income (loss) from continuing operations	216	271,188	270,972	*
Income from discontinued operations	228,412	121,490	(106,922)	(47)%
Net income attributable to Antero equity owners	$ 228,628	$ 392,678	$ 164,050	72%
EBITDAX from continuing operations(1)	$ 27,824	$ 160,259	$ 132,435	476%
EBITDAX from discontinued operations(1)	169,854	180,562	10,708	6%
Total EBITDAX(1)	$ 197,678	$ 340,821	$ 143,143	72%
Production data:				
Natural gas (Bcf)	11	45	34	317%
Oil (MBbl)		2	2	*
Combined (Bcfe)	11	45	34	317%
Daily combined production (MMcfe/d)	30	124	94	317%
Average sales prices before effects of cash settled derivatives(2):				
Natural gas (per Mcf)	$ 4.39	$ 4.33	$ (0.06)	(1)%
Oil (per Bbl)		$ 97.19	*	*
Combined (per Mcfe)	$ 4.39	$ 4.33	$ (0.06)	(1)%
Average realized sales prices after effects of cash settled derivatives(2):				

Natural gas (per Mcf)	$	5.78	$	5.44	$	(0.34)	(6)%
Oil (per Bbl)			$	97.19		*	*
Combined (per Mcfe)	$	5.78	$	5.44	$	(0.34)	(6)%
Average costs (per Mcfe)(2):							
Lease operating costs	$	0.11	$	0.10	$	(0.01)	(9)%
Gathering, compression, processing and transportation	$	0.85	$	0.83	$	(0.02)	(2)%
Production taxes	$	0.27	$	0.26	$	(0.01)	(4)%
Depletion, depreciation and amortization	$	1.71	$	1.24	$	(0.47)	(27)%
General and administrative	$	2.03	$	0.74	$	(1.29)	(64)%

(1) See "Selected Historical Consolidated Financial Data" included elsewhere in this prospectus for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

(2) Average sales prices shown in the table reflect both of the before and after effects of our cash settled derivatives. Our calculation of such after effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges. Oil and NGL production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

* Not meaningful or applicable.

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $47 million for the year ended December 31, 2010 to $195 million for the year ended December 31, 2011, an increase of $148 million or 312%. Our production increased by 317% from 11 Bcfe in 2010 to 45 Bcfe in 2011. The net increase in revenues resulted from production volume increases reduced by commodity price decreases. Production increases accounted for a $150 million, or 317%, increase in revenues (calculated as the increase in year-to-year volumes times the prior year average price). Price decreases accounted for a $2 million, or 5%, decrease in revenues (calculated as the decrease in year-to-year average price times current year production volumes).

Commodity derivative fair value gains. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our results of operations. For the years ended December 31, 2010 and 2011, our hedges resulted in derivative fair value gains of $78 million and $496 million, respectively. The derivative fair value gain included $15 million and $50 million of cash settlements received on derivatives for the years ended December 31, 2010 and 2011, respectively.

Lease operating expenses. Lease operating expenses increased from $1 million for the year ended December 31, 2010 to $5 million in 2011, an increase of $4 million, as a result of a 317% increase in production.

Gathering, compression, processing and transportation expense. Gathering, compression, processing and transportation expense increased from $9 million for the year ended December 31, 2010 to $37 million in 2011 because of the increase in production and increased firm transportation commitments. On a per-Mcfe basis, these expenses decreased slightly from $0.85 per Mcfe for 2010 to $0.83 per Mcfe for 2011.

Production tax expense. Total production taxes increased from $3 million for the year ended December 31, 2010 to $12 million for the year ended December 31, 2011, as a result of increased production. Production taxes as a percentage of natural gas and oil revenues before the effects of hedging were 6.1% in both years.

Exploration expense. Exploration expense increased from $2 million for the year ended December 31, 2010 to $4 million for the year ended December 31, 2011, primarily because of an increase in the cost of unsuccessful lease acquisition efforts as we materially increased the number of third-party lease brokers providing services to us in the Appalachian Basin.

Impairment of unproved properties. We abandon expired or soon to be expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as short remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly. Our impairment of unproved property expense decreased from $6 million for the year ended December 31, 2010 to $5 million for the year ended December 31, 2011.

DD&A. DD&A increased from $19 million for the year ended December 31, 2010 to $56 million for the year ended December 31, 2011, an increase of $37 million as a result of increased production. DD&A per Mcfe decreased from $1.71 per Mcfe to $1.24 per Mcfe, primarily as a result of increased reserve volumes in 2011 compared to 2010. As a successful efforts company, we evaluate the impairment of our proved natural gas, NGLs, and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the years ended December 31, 2010 or 2011 for proved properties. As of December 31, 2011, no significant well costs had been deferred for over one year pending proved reserves determination.

General and administrative expense. General and administrative expense increased from $22 million for the year ended December 31, 2010 to $33 million for 2011, an increase of $11 million. The increase is primarily due to increased costs related to salaries, employee benefits, contract personnel and professional services expenses for additional personnel required for our capital expenditure program and production levels. On a per-Mcfe basis, general and administrative expense decreased from $2.03 per Mcfe for the year ended December 31, 2010 to $0.74 per Mcfe for 2011. No portion of general and administrative expenses was allocated to discontinued operations as we do not expect any reduction of such expenses as a result of the sale of the Arkoma and Piceance properties. When all discontinued operations are included, general and administrative expenses decreased from $0.47 per Mcfe in 2010 to $0.37 per Mcfe in 2011.

Interest expense and interest rate derivative fair value losses. Interest expense increased from $56 million for the year ended December 31, 2010 to $74 million for 2011, an increase of $18 million, primarily as a result of increased borrowings on the credit facility and the issuance of $400 million of 7.25% senior notes in August 2011. We had entered into variable-to-fixed interest rate swap agreements that hedged our exposure to interest rate variations on our credit facility and second lien term loan facility. At December 31, 2010, one of these swaps remained outstanding with a notional amount of $225.0 million and a fixed pay rate of 4.11%. This swap expired in July 2011. For the year ended December 31, 2010, we had derivative fair value losses of $3 million. There were no outstanding interest swap agreements at December 31, 2011.

Income tax expense. Income tax expense related to continuing operations was $185 million in 2011 compared to $1 million in 2010 and is entirely comprised of deferred taxes in both years. In general, we have not generated current taxable income in either the current or prior years, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. Each of our operating subsidiaries filed separate federal and state tax returns in 2010 and 2011; therefore, our provision for income taxes for those years consists of the sum of our provisions for each of the operating entities. From time to time there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs and could significantly affect our future taxable position. The impact of any change will be recorded in the period that such legislation might be enacted.

Income from discontinued operations. Income from discontinued operations includes the results of operations from the Arkoma Basin and Piceance Basin operations (including revenues and direct operating expenses and allocated income tax expense, but not general and administrative or interest expenses). A detailed analysis of these operations is included in note 3 to the consolidated financial statements included elsewhere in this prospectus. Income from discontinued operations decreased from income of $228 million in 2010 to income of $121 million in 2011, primarily as a result of a nonrecurring gain of $148 million recognized in 2010 on the sale of our Arkoma midstream assets.

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been through issuances of debt securities, borrowings under our credit facility, asset sales, and net cash provided by operating activities. Our primary use of cash has been for the exploration, development and acquisition of natural gas, NGLs, and oil properties. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us. As of June 30, 2013, we had 4,576 identified potential horizontal well locations, which will take many years to develop. Additionally our proved undeveloped reserves will require an estimated $4.6 billion of development capital over the next five years. A significant portion of this capital requirement will be funded out of operating cash flows. However, we may be required to generate or raise significant capital to conduct drilling activities on these identified potential well locations and to finance the development of our proved undeveloped reserves.

During 2012, we raised capital through the issuance of $300 million of 6.00% senior notes due 2020, and in February 2013 we issued another $225 million of the 6.00% senior notes. During 2012, we also sold various properties for which we received cash proceeds of approximately $1.2 billion.

As of August 29, 2013, our credit facility was amended to increase the borrowing base to $2.0 billion and the lender commitments to $1.75 billion. Current lender commitments can be increased to the full borrowing base upon approval of the lending bank group. The borrowing base is determined every six months based on reserves, oil and gas commodity prices, and the value of our hedge portfolio. The next redetermination of the borrowing base is scheduled to occur in April 2014. Our commodity hedge position provides us with additional liquidity as it provides us with the relative certainty of receiving a significant portion of our future expected revenues from operations despite potential declines in the price of natural gas. Our ability to make significant additional acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. Our credit facility is funded by a syndicate of 16 banks. We believe that the participants in the syndicate have the capability to fund up to their current commitment. If one or more banks should not be able to do so, we may not have the full availability of our credit facility.

For the year ended December 31, 2012, our capital expenditures were approximately $1.68 billion for drilling, leasehold acquisitions, and gathering. In September 2013, we increased our capital budget by $500 million to $2.45 billion, including $1.45 billion for drilling and completion, $400 million for leasehold acquisitions, and $600 million for the construction of water handling infrastructure and gas gathering pipelines and facilities. The amount of our budget allocated to drilling and completion increased by $250 million in order to accommodate our use of shorter frac stage length completions, drill seven additional wells and fund additional pad construction costs. The amount of our budget allocated to land increased by $150 million to fund the acquisition of an additional 30,000 leasehold acres. Finally, the amount of our budget allocated to midstream was increased by $100 million to fund additional gathering infrastructure and to fund higher capital costs that we have incurred in some areas due to higher than average rainfall. As of June 30, 2013, we had spent approximately $1.2 billion of our 2013 capital budget. Our capital budget excludes acquisitions. Substantially all of the $1.45 billion allocated for drilling and completion is allocated to our operated drilling in rich gas areas. Approximately 85% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 15% is allocated to the Utica Shale. During 2013, we plan to operate an average of 15 drilling rigs in the Marcellus Shale and four drilling rigs in the Utica Shale. We periodically review our capital expenditures and adjust our budget accordingly. Historically, we have increased our budget to take advantage of opportunistic leasehold acreage acquisitions and new capital project opportunities. In addition, we have adjusted our drilling, completion and gathering budgets in response to drilling results, liquidity changes and commodity prices.

After the completion of this offering and the increase in lender commitments under our credit facility on June 27, 2013, together with our operating cash flow and hedging program, we believe we will have the financial flexibility to meet our cash requirements, including normal operating needs, and pursue our currently planned 2013 and 2014 delineation and development drilling activities.

For more information on our outstanding indebtedness, see " Debt Agreements and Contractual Obligations."

Table of Contents

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2010, 2011 and 2012 and for the six months ended June 30, 2012 and 2013 (including discontinued operations):

	Year Ended December 31,			Six Months Ended June 30,	
	2010	**2011**	**2012**	**2012**	**2013**
			(in thousands)		
Net cash provided by operating activities	$ 127,791	$ 266,307	$ 332,255	$ 160,984	$ 192,397
Net cash provided by (used in) investing activities	(230,672)	(901,249)	(463,491)	116,327	(1,178,408)
Net cash provided by (used in) financing activities	101,200	629,297	146,882	(275,079)	977,889
Net increase (decrease) in cash and cash equivalents	$ (1,681)	$ (5,645)	$ 15,646	$ 2,232	$ (8,122)

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $161 million and $192 million for the six months ended June 30, 2012 and 2013, respectively. The increase in cash flow from operations for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 was primarily the result of increased production volumes and revenues (including derivative settlements), net of the increase in cash operating costs, interest expense, and changes in working capital levels.

Net cash provided by operating activities was $128 million, $266 million and $332 million for the years ended December 31, 2010, 2011 and 2012, respectively. The increase in cash flows from operations for 2010 to 2011 and also from 2011 to 2012 was primarily the result of increased oil and gas production volumes and cash settlements received on commodity hedges, net of increased operating expenses and interest expense and changes in working capital.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas, NGLs, and oil prices. Prices for these commodities are determined primarily by prevailing market conditions. Factors including regional and worldwide economic activity, weather, infrastructure capacity to reach markets, and other variables influence market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see " Quantitative and Qualitative Disclosures About Market Risk."

Cash Flow From (Used in) Investing Activities

During the six months ended June 30, 2013, we used cash totaling $1.2 billion in investing activities, including $271 million of undeveloped leasehold acquisitions, $758 million of drilling costs, and $152 million of expenditures for gathering systems and facilities. During the six months ended June 30, 2012, we had positive cash flows from investing activities of $116 million as a result of proceeds realized from the sale of certain Marcellus gathering systems and rights and the Arkoma Basin properties totaling $811 million, partially offset by $695 million in land acquisitions, drilling and development, and gathering systems.

During the years ended December 31, 2010, 2011 and 2012, we used cash flows in investing activities of $231 million, $901 million and $463 million, respectively, as a result of our capital expenditures for drilling, development and acquisitions. During 2012 we spent approximately $1.7 billion on investments in undeveloped leaseholds, development costs and gathering systems. Net cash flow used in investing activities was reduced by realized cash proceeds of approximately

Table of Contents

$1.2 billion from the sale of the Piceance Basin, Arkoma Basin, and certain Appalachian gathering systems. The increase in cash flows used in investing activities in 2011 from 2010 resulted primarily from increased drilling and acquisition activities in the Marcellus Shale. In September 2011, we also acquired a 7% overriding royalty interest related to 115,000 net acres operated by us in the core of our West Virginia and Pennsylvania Marcellus acreage position for $193 million.

Our board of directors has approved a capital budget of up to $2.45 billion for 2013. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs, and oil prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash Flow Provided by (Used in) Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2013 of $978 million resulted from the issuance of $225 million of our 6.00% senior notes for net proceeds of approximately $232 million in February 2013, $743 million of net additional borrowings under our credit facility and other items of $3 million. Net cash used in financing activities of $275 million during the six months ended June 30, 2012 resulted from a repayment of borrowings under our credit facility.

Net cash provided by financing activities in 2012 of $147 million was primarily the result of (i) $300 million of cash provided by the issuance of senior notes, net of (ii) net repayments of the credit facility of $148 million and other items of $5 million including deferred financing costs.

Net cash provided by financing activities in 2011 of $629 million was primarily the result of (i) $400 million of cash provided by the issuance of senior notes, (ii) net borrowings of $265 million on our credit facility, net of (iii) cash outflows for $7 million of deferred financing costs, and a $29 million distribution to equity members for tax liabilities.

Net cash provided by financing activities in 2010 of $101 million was primarily a result of (i) $156 million of cash provided by the issuance of senior notes, (ii) net payments of $42 million on our credit facility, and (iii) $13 million of other payment items including deferred financing costs.

Debt Agreements and Contractual Obligations

Senior Secured Revolving Credit Facility.

Our credit facility was amended as of August 29, 2013 to provide for a borrowing base of $2.0 billion and lender commitments of $1.75 billion. The borrowing base is redetermined semiannually and depends on the volumes of our proved oil and gas reserves and estimated cash flows from these reserves and our commodity hedge positions. The next redetermination is scheduled to occur in April 2014. As of June 30, 2013, the borrowing base was $1.75 billion and lender commitments totaled $1.45 billion. At June 30, 2013, we had $960 million of borrowings and $32 million of letters of credit outstanding under the credit facility. At December 31, 2012, we had $217 million of borrowings and $43 million of letters of credit outstanding under the credit facility. The credit facility matures in May 2016.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the rate appearing on the Reuters BBA

Table of Contents

Libor Rates Page 3750 for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of our borrowing base utilized.

The credit facility is secured by mortgages on substantially all of our properties and guarantees from our subsidiaries. Interest is payable at a variable rate based on LIBOR or the prime rate based on our election at the time of borrowing. As of June 30, 2012 and 2013, borrowings and letters of credit outstanding under our credit facility had a weighted average interest rate of 2.1%. The credit facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain payments to Antero Resources LLC;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The credit facility, as amended, also requires us to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (includes unused commitment under the credit facility and excludes derivative assets) to our consolidated current liabilities of 1.0 to 1.0 at the end of each fiscal quarter; and
- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX to consolidated interest expense, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2012 and June 30, 2013.

Senior Notes. We have $525 million of 9.375% senior notes outstanding, which are due December 1, 2017. The notes were issued by Antero Resources Finance Corporation, or Antero Finance, and are unsecured and effectively subordinated to the credit facility to the extent of the value of the collateral securing the credit facility. The notes are guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after December 1, 2013 at redemption prices ranging from 104.688% on or after December 1, 2013 to 100.00% on or after December 1, 2015. At any time prior to December 1, 2013, Antero Finance may also redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium. If Antero Resources LLC undergoes a change of control, Antero Finance may be required to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

We also have $400 million of 7.25% senior notes outstanding, which are due August 1, 2019. The notes were issued by Antero Finance and are unsecured and effectively subordinated to the credit facility to the extent of the value of the collateral securing the credit facility. The notes rank pari passu

Table of Contents

to the existing 9.375% senior notes. The notes are guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on August 1 and February 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after August 1, 2014 at redemption prices ranging from 105.438% on or after August 1, 2014 to 100.00% on or after August 1, 2017. In addition, on or before August 1, 2014, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 107.25% of the principal amount of the notes, plus accrued interest. At any time prior to August 1, 2014, Antero Finance may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If Antero Resources LLC undergoes a change of control, Antero Finance may be required to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

At June 30, 2013, we also had $525 million of 6.00% senior notes outstanding, which are due December 1, 2020. The notes were issued by Antero Finance and are unsecured and effectively subordinated to the credit facility to the extent of the value of the collateral securing the credit facility. The notes rank pari passu to the existing 9.375% and 7.25% senior notes. The notes are guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after December 1, 2015 at redemption prices ranging from 104.50% on or after December 1, 2015 to 100.00% on or after December 1, 2018. In addition, on or before December 1, 2015, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 106.00% of the principal amount of the notes, plus accrued interest. At any time prior to December 1, 2015, Antero Finance may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If a change of control (as defined in the bond indenture) occurs at any time prior to January 1, 2014, Antero Finance may, at its option, redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the notes, plus accrued interest. If Antero Finance has not exercised its optional redemption rights upon a change of control, the note holders will have the right to require Antero Finance to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

We used the proceeds from the issuances of the senior notes to repay borrowings outstanding under our credit facility and for development of our oil and natural gas properties.

The senior notes indentures each contain restrictive covenants and restrict our ability to incur additional debt unless a pro forma minimum interest coverage ratio requirement of 2.25:1 is incurred. We were in compliance with such covenants and the coverage ratio requirement as of December 31, 2012 and June 30, 2013.

Following the merger of Antero Resources LLC into Antero Resources Corporation, as described in "Corporate Reorganization," Antero Resources Corporation will assume the obligations of Antero Resources LLC as parent guarantor under the indentures governing our senior notes. In addition, Antero Investment will not be a guarantor under our credit facility or under the indentures governing our senior notes or otherwise subject to the restrictive covenants thereunder.

Treasury Management Facility. We have a stand-alone revolving note with a lender under the credit facility which provides for up to $25 million of cash management obligations in order to facilitate our daily treasury management. Borrowings under the revolving note are secured by the collateral for the credit facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2014. We expect that the treasury management facility will be renewed for an

Table of Contents

additional one year period when it expires. At December 31, 2012 and June 30, 2013, there were no outstanding borrowings under this facility.

Note Payable. We assumed a $25 million unsecured note payable in the Bluestone Energy Partners business acquisition consummated on December 1, 2010. The note had a balance of $25 million at December 31, 2012 and June 30, 2013, bears interest at 9%, and is due December 1, 2013. The note is not callable.

Intercompany Credit Arrangement. In connection with the closing of this offering, we intend to enter into an intercompany credit agreement with Antero Midstream. The intercompany credit agreement provides that we will make available to Antero Midstream up to $500 million in revolving credit facility borrowings from time to time. The facility will mature on the earlier of May 12, 2016 or the consummation of Antero Midstream's initial public offering. Interest on borrowings under the facility is payable by Antero Midstream at a rate equal to three-month LIBOR for the relevant borrowing period plus 2.5%.

Contractual Obligations. A summary of our contractual obligations as of June 30, 2013 for the next five years and thereafter is provided in the following table. See "Business Our Operations Delivery Commitments" for additional information on our delivery commitments.

	Year						
(in millions)	**1**	**2**	**3**	**4**	**5**	**Thereafter**	**Total**
Credit facility(1)	$	$	$ 960	$	$	$	$ 960
Senior notes principal(2)	25				525	925	1,475
Senior notes interest(2)	111	110	110	110	85	122	648
Drilling rig and frac service commitments(3)	168	100	26				294
Firm transportation(4)	72	130	141	139	138	959	1,579
Gas processing, gathering, and compression service(5)	137	149	163	163	159	680	1,451
Office and equipment leases	2	4	5	4	4	17	36
Asset retirement obligations(6)						11	11
Total	$ 515	$ 493	$ 1,405	$ 416	$ 911	$ 2,714	$ 6,454

(1) Includes outstanding principal amount at June 30, 2013. This table does not include future commitment fees, interest expense, or other fees on the credit facility because they are floating-rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged.

(2) Includes the 9.375% senior notes due 2017, the 7.25% senior notes due 2019, and the 6.00% senior notes issued in November 2012 and February 2013 and due 2020, and the $25 million note due 2013 assumed in the acquisition of Bluestone Energy Partners.

(3) At June 30, 2013, we had contracts for rig services which expire at various dates from 2013 through 2016. We also had two frac services contracts which expire in 2013 and 2014. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(4) We have entered into firm transportation agreements with various pipelines in order to facilitate the delivery of production to liquid markets. These contracts commit us to transport minimum daily natural gas or NGL volumes at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to

pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(5)
Contractual commitments for gas processing, gathering, and compression service agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression agreements. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(6)
Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See note 2 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Incentive Plan

Employee Holdings currently holds membership interests in Antero Resources LLC and has granted profits interests to our employees. The profits interests currently have rights to participate in certain distribution events of Antero Resources LLC if sufficient valuation thresholds are met. Historically, we have accounted for this plan as a profits interests plan and did not record stock compensation expense because the satisfaction of all performance, market, and service conditions, which would only occur upon a liquidating event, was not probable.

The limited liability company agreement of Antero Investment to be adopted in connection with the closing of this offering provides a mechanism by which the shares of our common stock to be allocated amongst the members of Antero Investment, including Employee Holdings, will be determined. As a result, the satisfaction of all performance, market, and service conditions relative to the membership interests awards held by Employee Holdings will be probable. Accordingly, we will recognize a non-cash charge for stock compensation expense for the estimated fair value of the prospective distributions to Employee Holdings at the closing of this offering and over the remaining service period. We will retain an independent valuation firm to estimate the fair value of the shares to be distributed in satisfaction of the profits interests.

Table of Contents

Natural Gas, NGL and Oil Properties

Successful Efforts Method

Our natural gas, NGL, and oil exploration and production activities are accounted for using the successful efforts method. Under this method, costs of drilling successful exploration wells and development costs are capitalized and amortized on a geological reservoir basis using the unit-of-production method as natural gas, NGL, and oil is produced. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not discover proved reserves are expensed as exploration costs. The costs of development wells are capitalized whether productive or nonproductive. Natural gas, NGL, and oil lease acquisition costs are also capitalized. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unproved property costs are costs related to unevaluated properties and are transferred to proved natural gas and oil properties if the properties are determined to be productive. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain until all costs are recovered. Unevaluated natural gas, NGL, and oil properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage. If it is determined that it is probable that reserves will not be discovered, the cost of unproved leases is charged to impairment of unproved properties. During the years ended December 31, 2010, 2011 and 2012 and the six months ended June 30, 2012 and 2013, we charged impairment expense for expired or expiring leases with a cost of $36 million, $11 million, $13 million, $2 million and $6 million, respectively. The assessment of unevaluated natural gas, NGL, and oil properties to determine any possible impairment requires managerial judgment.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in anticipation of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial, which will result in additional exploration expenses when incurred. Additionally, the application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Natural Gas, NGL and Oil Reserve Quantities and Standardized Measure of Future Cash Flows

Our independent reserve engineers and internal technical staff prepare the estimates of natural gas, NGL, and oil reserves and associated future net cash flows. Current accounting guidance allows only proved natural gas, NGL, and oil reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of natural gas, NGL, and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our independent reserve engineers and internal technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Natural gas, NGL, and oil reserve engineering is a subjective process of estimating underground accumulations of natural gas, NGL, and oil that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, natural gas, NGL, and oil prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of natural gas, NGL, and oil that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Impairment of Proved Properties

We review our proved natural gas, NGL, and oil properties for impairment on a geological reservoir basis whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our gas and oil properties and compare these future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the natural gas, NGL, and oil properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded. We did not record any impairment charges for proved properties in 2010, 2011 or 2012.

Off-Balance Sheet Arrangements

As of June 30, 2013, we did not have any off-balance sheet arrangements other than operating leases and contractual commitments for drilling rigs, frac services, firm transportation, and gas processing, gathering and compression. See " Contractual Obligations" for commitments under operating leases, drilling rig and frac service agreements, firm transportation agreements, and gas processing and compression service agreements.

Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGL, and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Hedging Activities

Our primary market risk exposure is in the price we receive for our natural gas and oil production. Realized pricing is primarily driven by spot regional market prices applicable to our U.S. natural gas production and the prevailing worldwide price for crude oil. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, we have entered into financial commodity swap contracts to receive fixed prices for a

Table of Contents

portion of our natural gas and oil production when management believes that favorable future prices can be secured. We hedge part of our production at a fixed price for natural gas at our sales points (New York Mercantile Exchange ("NYMEX") less basis) to mitigate the risk of differentials to the sales point prices. Part of our production is also hedged at NYMEX prices.

Our financial hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to natural gas price fluctuations. The counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price. These contracts may include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty and cashless price collars that set floor and ceiling prices for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference.

At June 30, 2013, we had in place natural gas and oil swaps covering portions of our projected production from 2013 through 2018. Our commodity hedge position as of June 30, 2013 is summarized in note 8 to our unaudited condensed consolidated financial statements included elsewhere herein. Our financial hedging activities are intended to support natural gas, NGL, and oil prices at targeted levels and to manage our exposure to natural gas price fluctuations. Our credit facility allows us to hedge up to 85% of our estimated production from proved reserves for up to 12 months in the future, 80% for 13 to 24 months in the future, 75% for 25 to 36 months in the future, 70% for 37 to 48 months in the future, 65% for 49 to 60 months in the future, and 65% of production for 2019. Based on our annual production and our fixed price swap contracts in place during 2013, our income before taxes for the six months ended June 30 2013 would have decreased by approximately $0.4 million for each $0.10 decrease per MMBtu in natural gas prices.

All derivative instruments, other than those that meet the normal purchase and normal sales exception, are recorded at fair market value in accordance with U.S. GAAP and are included in the consolidated balance sheets as assets or liabilities. Fair values are adjusted for non-performance risk. Because we do not designate these hedges as accounting hedges, we do not receive accounting hedge treatment and all mark-to-market gains or losses as well as cash receipts or payments on settled derivative instruments are recognized in our results of operations as "Derivative fair value gains (losses)."

Mark-to-market adjustments of derivative instruments produce earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled. We expect continued volatility in the fair value of our derivative instruments. Our cash flow is only impacted when the underlying physical sales transaction takes place in the future and when the associated derivative instrument contract is settled by making or receiving a payment to or from the counterparty. At June 30, 2013 and December 31, 2012, the estimated fair value of our commodity derivative instruments was a net asset of $593 million and $532 million, respectively, comprised of current and noncurrent assets and current liabilities. None of these commodity derivative instruments were entered into for trading or speculative purposes.

By removing price volatility from a portion of our expected natural gas production through December 2018, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices.

Table of Contents

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our credit facility, which has a floating interest rate. The average annual interest rate incurred on this indebtedness for the six months ended June 30, 2013 was approximately 2.1%. A 1.0% increase in each of the average LIBOR rate and federal funds rate for the six months ended June 30, 2013 would have resulted in an estimated $2.1 million increase in interest expense for that period. We had no outstanding interest rate derivatives for hedging purposes at June 30, 2013.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($593 million at June 30, 2013) and the sale of our oil and gas production ($66 million at June 30, 2013), which we market to energy companies.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with eleven different counterparties, all but one of which is a lender under our credit facility. The fair value of our commodity derivative contracts of approximately $593 million at June 30, 2013 includes the following values by bank counterparty: BNP Paribas $150 million; Credit Suisse $161 million; Wells Fargo $99 million; JP Morgan $102 million; Barclays $65 million; Deutsche Bank $11 million; Union Bank $2 million; and Toronto Dominion Bank $1 million. Additionally, contracts with Dominion Field Services account for $2 million of the fair value. The credit ratings of certain of these banks have been downgraded because of the sovereign debt crisis in Europe. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available or, if not available, a discount rate based on the applicable Reuters bond rating) at June 30, 2013 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by the credit facility, we are not required to provide credit support or collateral to any of our counterparties under our contracts, nor are they required to provide credit support to us. As of June 30, 2013, we did not have past-due receivables from or payables to any of our counterparties.

We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Table of Contents

BUSINESS

Our Company

We are an independent oil and natural gas company engaged in the exploitation, development and acquisition of natural gas, NGLs and oil properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. We are focused on creating shareholder value through the development of our large portfolio of repeatable, low cost, liquids-rich drilling opportunities in two of the premier North American shale plays. We currently hold approximately 329,000 net acres in the southwestern core of the Marcellus Shale and approximately 102,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 170,000 net acres of our Marcellus Shale leasehold are prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on a portion of our Marcellus Shale acreage in West Virginia that we believe is prospective for the dry gas Utica Shale. As of June 30, 2013, our estimated proved, probable and possible reserves were 6.3 Tcfe, 14.0 Tcfe and 7.4 Tcfe, respectively, and our proved reserves were 23% proved developed and 91% natural gas, assuming ethane rejection. As of June 30, 2013, our drilling inventory consisted of 4,576 identified potential horizontal well locations, approximately 64% of which are liquids-rich drilling opportunities.

Our management team has a proven track record of implementing geologically driven growth strategies in some of the most prominent unconventional plays across the United States, including the Barnett, Woodford, Marcellus and Utica Shales. Paul Rady, our Chairman and Chief Executive Officer, and Glen Warren, our President and Chief Financial Officer, founded our business in 2002. The majority of our management team has worked together at various times for over 30 years at Amoco Production Company, Barrett Resources Corporation, Pennaco Energy Inc. and Antero Resources. Our management team has created significant shareholder value through various past ventures, including the sale of two unconventional resource-focused upstream companies and one midstream company in the last 15 years.

We have been successful in targeting large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs and oil from unconventional formations. We have been early adopters of innovative hydraulic fracturing and completion techniques, having drilled over 450 horizontal wells in the Barnett, Woodford, Marcellus and Utica Shales. As a result of our horizontal drilling and completion expertise, and the predictable geologic structure throughout our largely contiguous land position in the southwestern core of the Marcellus Shale, we have drilled approximately 1.3 million lateral feet without encountering any faulting in our target zone. We have drilled and completed 199 horizontal wells in the Marcellus Shale with a 100% success rate to date. With 15 rigs running, we are currently the most active driller in the Marcellus Shale based on information from RigData. We have begun to apply the expertise and approach we employ in the Marcellus Shale to the Utica Shale, and we believe we will be able to achieve similar success. We have drilled and completed 11 horizontal wells in the Utica Shale with a 100% success rate without encountering any faulting.

Our net daily production in the second quarter of 2013 averaged 458 MMcfe/d, including 4,160 Bbls/d of NGLs and oil. Further, our estimated average net daily production for the month of August 2013 was 594 MMcfe/d, including 8,630 Bbls/d of NGLs and oil. We grew proved reserves at a compounded annual growth rate of 96% from 2006 to 2012, despite the 2012 divestiture of our Arkoma and Piceance Basin properties. Additionally, from January 1, 2012 to June 30, 2013, we increased our Appalachian proved reserves by 47% to 6.3 Tcfe, assuming ethane rejection at each date.

Table of Contents

The charts below illustrate the growth in our average net daily production on an overall basis since 2006 and in the Appalachian Basin since 2010:

Antero Average Net Daily Production **Antero Appalachian Basin Average Net Daily Production**

(1) CAGR means compounded annual growth rate.

2013 Capital Budget

For the year ended December 31, 2012, our capital expenditures were approximately $1.68 billion for drilling, leasehold acquisitions and gathering. Our capital budget for 2013 is $2.45 billion and includes:

- $1.45 billion for drilling and completion, substantially all of which is allocated to our operated drilling in liquids-rich gas areas;
- $600 million for the construction of gathering pipelines and facilities in the Appalachian Basin (including $250 million for water handling infrastructure, primarily in the Marcellus Shale); and
- $400 million for leasehold acquisitions.

As of June 30, 2013, we had spent approximately $1.2 billion of our 2013 capital budget. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, commodity prices and the availability of opportunistic acreage acquisitions.

Our Properties

The Appalachian Basin, which covers over 185,000 square miles in portions of Kentucky, Tennessee, Virginia, West Virginia, Ohio, Pennsylvania and New York, is considered a highly attractive energy resource producing region with a long history of oil, natural gas and coal production. Importantly, the Appalachian Basin is strategically located near the high energy demand markets of the northeast United States, which has historically resulted in relatively higher realized sales prices due to the reduced transportation costs a purchaser must incur to transport commodities to end users. Based on production, the Appalachian Basin is the third largest overall gas field in the United States with over 9 Bcfe/d in 2012. Over the past five years, the focus of many producers has shifted from the younger, shallower conventional sandstone and carbonate reservoirs to the older, deeper Marcellus Shale and the newly emerging Utica Shale plays, which has driven Appalachian basin production growth. The Marcellus Shale accounted for over 7 Bcfe/d of the 2012 production making it the third largest United States gas field on a stand-alone basis, and the largest unconventional gas play in the world.

88

Table of Contents

Marcellus Shale

We believe that the Marcellus Shale is a premier North American shale play due to its high well recoveries relative to drilling and completion costs, broad aerial extent, relatively homogeneous high-quality reservoir characteristics and significant hydrocarbon resources in place. Based on these attributes, as well as drilling results publicly released by other operators, we believe that the Marcellus Shale offers some of the most attractive single-well rates of return of all North American conventional and unconventional play types. We also believe that the Marcellus Shale has two core areas: the southwestern core in northern West Virginia and southwestern Pennsylvania and the northeastern core in northeastern Pennsylvania. According to RigData, as of September 2013, approximately 90% of the 91 drilling rigs operating in the Marcellus Shale were located in these two core areas.

The Devonian-aged Marcellus Shale is an unconventional reservoir that produces natural gas, NGLs and oil and is one of the largest natural gas fields in the country. The productive limits of the Marcellus Shale cover over 50,000 square miles within Pennsylvania, West Virginia, Ohio and New York. The Marcellus Shale is a black, organic-rich shale deposit generally productive at depths between 5,500 and 7,000 feet. Production from the brittle, gas-charged shale reservoir is best derived from hydraulically fractured horizontal wellbores that exceed 2,000 feet in lateral length and involve multi-stage fracture stimulations. The geology of the Marcellus Shale is analogous to the Barnett, Woodford and Fayetteville Shales, where we and our management team have successfully drilled and completed over 200 horizontal wells.

All of our approximately 329,000 net acres in the Marcellus Shale are located within the southwestern core. We have experienced virtually no geologic complexity in our drilling activities to date, which has contributed to what we believe to be a narrow and predictable band of expected well recoveries per 1,000 feet of lateral length on our wells. Further, the lower thermal maturity of the Marcellus Shale in the western half of the southwestern core yields liquids-rich natural gas and condensate, which allows for NGL processing that can significantly improve well economics.

Our intensive operational focus and leasehold consolidation efforts, coupled with the favorable geology of our position, makes the Marcellus Shale highly attractive. We completed 71 gross (67 net) horizontal Marcellus Shale wells in 2012 and 62 gross (61 net) horizontal Marcellus Shale wells in the six months ended June 30, 2013. As of June 30, 2013, we had a total of 415 gross (379 net) producing wells in the Marcellus Shale. We had an additional 41 gross (39 net) wells drilling or waiting on completion as of June 30, 2013 in the play. As of June 30, 2013, we had approximately 2,941 identified gross undrilled horizontal well locations in the Marcellus Shale.

For the three months ended June 30, 2013, we had average net daily production of 457 MMcfe/d in the Marcellus Shale. Further, our estimated average net daily production for the month of August 2013 in the Marcellus Shale was 549 MMcfe/d, including 6,528 Bbls/d of NGLs and oil. We currently have 15 rigs operating in the Marcellus Shale and expect to drill 135 wells in 2013, of which 74 had been drilled as of June 30, 2013. We believe our full cycle drilling, completion and operating costs on a per unit basis are among the lowest in the Marcellus Shale and the industry as a whole.

Table of Contents

The following table provides a summary of our current gross and net acreage by county in the Marcellus Shale.

County	Gross Acres	Net Acres
Doddridge, WV	136,332	104,196
Gilmer, WV	1,649	1,381
Harrison, WV	114,185	113,198
Lewis, WV	62	62
Marion, WV	4,275	3,911
Monongalia, WV	1,835	1,686
Pleasants, WV	1,503	810
Ritchie, WV	54,343	43,815
Tyler, WV	44,925	30,546
Wetzel, WV	4,481	2,525
Fayette, PA	7,680	5,423
Greene, PA	2,653	2,174
Washington, PA	12,654	12,205
Westmoreland, PA	7,073	6,919
Total	393,650	328,851

Utica Shale

The Ordovician-aged Utica Shale is an unconventional reservoir underlying the Marcellus Shale. The productive limits of the Utica Shale cover over 80,000 square miles within Ohio, Pennsylvania, West Virginia and New York. The Utica Shale is an organic-rich continuous black shale, with most production occurring at vertical depths between 7,000 and 10,000 feet. To date, the rich and dry gas windows of the Utica Shale play have yielded the strongest results. The richest and thickest concentration of organic-carbon content is present within the Point Pleasant Shale layer of the Lower Utica formation. The Point Pleasant Shale is therefore our primary targeted development play of the Utica Shale.

Based on initial drilling results and the first two months of production for our 11 Utica wells, we believe that the Utica Shale is a premier North American shale play. We believe that the core area is located in the southern portion of the play, which has been defined by significant drilling activity by several operators. We own approximately 102,000 net acres in the core of the Utica Shale and expect to add to our sizeable land position. The proximity of our Utica acreage position to our operations in the Marcellus Shale allows us to capitalize on operating and midstream synergies. We are currently operating four drilling rigs in the Utica Shale and have completed 11 horizontal wells with strong results. We have had a 100% success rate and believe over 90% of our acreage has liquids-rich gas processing potential. We expect to drill 26 wells in the Utica Shale in 2013, of which 11 had been drilled as of June 30, 2013. As of June 30, 2013, we had approximately 720 identified gross undrilled horizontal well locations in the Utica Shale. For the three months ended June 30, 2013, we had average net daily production of 1 MMcfe/d in the Utica Shale. Further, our estimated average net daily production for the month of August 2013 in the Utica Shale was 45 MMcfe/d, including 2,102 Bbls/d of NGLs and oil.

Table of Contents

The following table provides a summary of our current gross and net acreage by county in the Utica Shale.

County	Gross Acres	Net Acres
Athens, OH	84	84
Belmont, OH	13,095	11,734
Guernsey, OH	10,019	8,329
Harrison, OH	26	26
Monroe, OH	40,164	35,231
Noble, OH	61,661	46,379
Total	125,049	101,783

Operating Data

The following table provides a summary of our net acreage and identified potential well locations as of June 30, 2013, our 2013 and 2014 projected drilling schedules based on gross wells, and our average net daily production for August 2013:

	As of June 30, 2013							
		Identified Potential Well Locations(2)						
	Net Acres(1)	Total	Proved Undeveloped	Probable	Possible	2013 Projected Drilling Schedule (Gross Wells)	Planned 2014 Drilling Schedule (Gross Wells)	Average Net Daily Production (MMcfe/d)
Marcellus Shale:								
Highly Rich/Condensate(3)	48,000	505	18	454	33	4	21	16
Highly Rich Gas(3)	89,000	777	116	653	8	51	54	149
Rich Gas(3)	77,000	673	276	396	1	75	75	188
Dry Gas(3)	106,000	986	277	530	179	5		192
Utica Shale	100,000	720	17	175	528	26	47	45
Upper Devonian Shale	170,000	915	7	149	759			4
Total		4,576	711	2,357	1,508	161	197	594

(1) Net acres prospective for the Upper Devonian Shale are also included among the Marcellus Shale net acres. The Upper Devonian Shale and the Marcellus Shale are stacked formations within the same geographic footprint.

(2) Our proved undeveloped, probable and possible identified potential well locations are based on specifically engineered locations to which the applicable category of reserves were attributable based on SEC pricing as of June 30, 2013. For a description of how we determine our identified potential well locations, see " Our Operations Reserve Data Identification of Potential Well Locations."

(3) Classifications are based on our and other operators' drilling results in the Marcellus Shale and are subject to confirmation through actual future drilling results. For definitions of "highly rich/condensate," "highly rich gas," "rich gas" and "dry gas," see the "Glossary of Natural Gas and Oil Terms" in Annex A of this prospectus.

A majority of these potential locations have not been scheduled by management as part of our future multi-year drilling schedule and may not ultimately be completed to the extent we have insufficient resources to do so. We will be required to generate or raise significant capital to conduct such drilling activities. Any drilling activities we are able to conduct on these potential locations may

Table of Contents

not be successful or result in our ability to add additional proved reserves to our overall proved reserves.

Midstream Operations

Our exploration and development activities are supported by our operated natural gas gathering, compression, processing and transportation assets, as well as by third-party arrangements. Unlike many producing basins in the United States, certain portions of the Appalachian Basin do not have sufficient midstream infrastructure to support the existing and expected increasing levels of production. Actively managing these midstream operations allows us to ensure that we can obtain the necessary takeaway and processing capacity for our production and, when necessary or advisable, process our liquids-rich natural gas production to maximize the value that we can obtain for our products.

We maintain a strong commitment to developing the necessary midstream infrastructure to support our drilling schedule and production growth. We accomplish this goal through a combination of internal asset developments and contractual relationships with third-party midstream service providers. As part of our internal developments, we have invested a significant amount of capital in building low- and high-pressure gathering lines, compression facilities and water pipeline systems. In the past we have monetized certain midstream infrastructure assets for a significant return on investment and redeployed the proceeds into our ongoing operations. We will continue to invest significantly in our midstream infrastructure, as it allows us to optimize our processing and takeaway capacity to support our expected rapid production growth, affords us more control over the direction and planning of our drilling schedule and has historically created significant value for our equity owners. In 2013, we estimate we will spend a total of approximately $600 million on midstream infrastructure. In addition, we believe that our midstream assets may be well suited for a MLP or similar structure. Accordingly, following the closing of this offering, we intend to contribute our midstream assets to Antero Midstream and enter into commercial arrangements for midstream services with them. Following the completion of this offering, we may also seek opportunities to finance our midstream business on a stand-alone basis. See "Certain Relationships and Related Party Transactions Antero Midstream" and "Corporate Reorganization."

Transportation and Takeaway Capacity

Our primary firm transportation commitments include the following:

- We have several firm transportation contracts for volumes that increase from 268,000 MMBtu per day in 2013 to approximately 582,000 MMBtu per day in 2015 on the Columbia Gas Transmission Pipeline, which takes Marcellus natural gas to the Leach Delivery Point. We have firm transportation contracts from the Leach Delivery Point for volumes that increase from 227,000 MMBtu per day in 2013 to 460,000 MMBtu in 2015 on the Columbia Gulf Pipeline, which takes natural gas from the Leach Delivery Point to the Gulf Coast. The contracts expire at various dates from 2017 through 2025.

- We have various firm transportation contracts for approximately 353,500 MMBtu per day taking Marcellus natural gas to various other delivery points; these contracts expire in 2022.

- We have a firm transportation contract for 200,000 MMBtu per day on the Rockies Express Pipeline, or REX, beginning in January 2014 to take Utica gas to the Midwestern Gas Transmission pipeline, or Midwestern, which delivers natural gas to Chicago. We have 140,000 MMBtu of firm transportation on the Midwestern pipeline. We can also deliver natural gas into the Midwestern pipeline from our Columbia Gulf capacity through a southern interconnection to the Midwestern. The Rex and Midwestern firm transportation commitments expire in 2021.

We have a firm transportation contract for approximately 20,000 Bbl per day on the Enterprise Products Partners ATEX pipeline beginning in the first quarter of 2014 to take ethane from Appalachia to Mont Belvieu, Texas. The ATEX firm transportation commitment expires in 2028.

In addition to the firm transportation that we control, we also have firm sales commitments to third parties who hold firm capacity on downstream interstate pipelines, or will utilize our firm transportation, for approximately 240,000 MMBtu per day increasing to 420,000 MMBtu per day in 2014. Our firm transportation capacity is utilized for 100,000 MMBtu of the firm sales.

Under firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Debt Agreements and Contractual Obligations" for information on our minimum fees for such contracts.

We continue to actively identify and evaluate additional processing and takeaway capacity to enhance the value of our Appalachian Basin position.

Natural Gas Processing

Our positions in the Marcellus and Utica Shales allow us to produce liquids rich natural gas that contains a significant amount of NGLs. Natural gas containing significant amounts of NGLs must be processed, which involves the removal and separation of NGLs from the wellhead natural gas in order to meet quality specifications of long-haul intrastate and interstate pipelines.

NGLs are valuable commodities once removed from the natural gas stream and fractionated into their key components. Fractionation refers to the process by which an NGL stream is separated into individual NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. Fractionation occurs by heating the mixed NGL stream to allow for the separation of the component parts based on the specific boiling points of each product. Each of the individual products are marketed to different end user markets and consequently have their own market price.

Market prices for NGLs have exhibited heightened variability over the last few years as shale gas production has increased and new gas midstream infrastructure projects have been constructed. During 2012, prices for each of the individual NGL products decreased significantly, and some NGL products experienced larger declines than others. In particular, market prices for ethane at Mont Belvieu declined substantially driven by a surge in NGL production, combined with limited NGL processing and transportation capacity and end user demand constraints. In the Marcellus Shale region, additional infrastructure to transport ethane to end user markets, including Mont Belvieu and Sarnia, Ontario, is being developed.

The combination of infrastructure constraints in the Appalachian region and low ethane prices has resulted in many producers "rejecting" rather than "recovering" ethane. Ethane rejection occurs when ethane is left in the wellhead gas stream when the gas is processed, rather than being separated out and sold as a liquid after fractionation. When ethane is left in the gas stream, the BTU content of the residue gas at the outlet of the processing plant is higher. Producers will elect to "reject" ethane when the price received for the higher BTU residue gas is greater than the price received for the ethane being sold as a liquid after fractionation. When ethane is recovered, the BTU content of the residue gas is lower, but a producer is then able to recover the value of the ethane sold as a separate NGL product. In addition, gas processing plants can produce the other NGL products (propane, normal butane, isobutane and natural gasoline) while rejecting ethane.

The high liquids content of our natural gas production results in us achieving significantly higher realizations after processing, which together with our low operating and development costs, leads to high rates of return on our drilling program. Given the existing commodity price environment and the lack of an ethane market in the northeast, we are currently rejecting ethane when processing our liquids-rich gas; however, we realize a significant pricing upgrade when selling the remaining NGL product stream at current prices. We will elect to recover ethane when ethane prices recover and the value we receive for the ethane is greater than the BTU equivalent residue gas.

Table of Contents

Our typical NGL barrel, assuming ethane recovery for 1,250 BTU gas, is composed of 58% ethane, 23% propane, 9% pentanes, 7% normal butane and 3% isobutane. At June 30, 2013, the blended value of this NGL barrel was approximately $17.32/Bbl. When we elect to reject ethane, we sell the ethane as BTU equivalent in our residue gas and our typical NGL barrel for 1,250 BTU gas is composed of approximately 51% propane, 21% pentanes, 16% normal butane, 9% isobutane and 3% ethane. At June 30, 2013, the blended value of an NGL barrel while rejecting ethane was $41.11/Bbl.

Long-term demand for NGLs is expected to increase materially driven by large expansions in end user demand.

As of June 30, 2013, we owned and operated 77 miles of gathering pipelines in the Marcellus Shale and had access to an additional 31 miles of low-pressure pipelines owned and operated by Crestwood and 63 miles of high-pressure pipelines owned and operated by Energy Transfer Partners L.P. and MarkWest. Additionally, as of June 30, 2013, we owned and operated four compressor stations and utilized nine additional third-party compressor stations in the Marcellus Shale. The gathering, compression and dehydration services provided by third parties are contracted on a fixed-fee basis. For 2013, we estimate we will spend $650 million on midstream infrastructure in the Marcellus Shale, including on low- and high-pressure gathering lines and the water pipeline system in order to support our planned drilling activities in the Marcellus Shale.

As of June 30, 2013, we owned and operated one mile of low-pressure pipeline in the Utica Shale. As of June 30, 2013, we utilized one third-party compressor station in the Utica Shale.

Through third-party contractual relationships, we have obtained committed cryogenic processing capacity for our Marcellus and Utica Shale production. For example, we have contracted with MarkWest to provide processing capacity as follows:

	Plant Processing Capacity (MMcf/d)	Contracted Firm Processing Capacity (MMcf/d)(1)	Anticipated Date of Completion
Marcellus Shale:			
Sherwood I	200	200	In service
Sherwood II	200	200	In service
Sherwood III	200	150	Fourth Quarter 2013
Sherwood IV	200	200	Second Quarter 2014
Marcellus Shale Total	800	750	
Utica Shale:			
Cadiz(2)	185		In service
Seneca I	200	200	Fourth Quarter 2013
Seneca II(3)	200		Fourth Quarter 2013
Seneca III(4)	200	100	First Quarter 2014
Utica Shale Total	785	300	

(1) Contracted firm capacity at the Sherwood and Seneca facilities as of the start-up date of each identified unit.

(2) Firm interim capacity of 80 MMcf/d at Cadiz will be fixed at 50 MMcf/d capacity upon start-up of the Seneca I processing complex and will terminate upon start-up of the Seneca II processing complex.

(3) We have 50 MMcf/d of interim capacity at the Seneca II processing facility until July 1, 2014.

(4) Remaining 100 MMcf/d of capacity at the Seneca III processing complex is available for commitment at our option.

Table of Contents

Our NGL processing capacity at the Sherwood facility has been curtailed since August 2013 due to a line break in a MarkWest NGL pipeline caused by a landslide due to abnormal rainfall. Repairs and remediation to the pipeline and rights of way in the landslide impacted areas are currently underway, and MarkWest is working to return the pipeline to service, which is expected to be in October 2013. While our NGLs from that facility are being transported by truck for fractionation and sale, we estimate that our net daily production since August 2013 has been reduced by 60 to 80 MMcfe/d as a result of this line break in order to match NGL production to trucking capacity. We do not expect the temporary NGL processing capacity constraints at the Sherwood facility to have a material impact on our results of operations.

Our midstream infrastructure also includes two independent fresh water sourcing and delivery systems for well completion operations in our Marcellus and Utica Shale operating areas. These systems consist of permanent buried pipelines, temporary surface pipelines and fresh water storage facilitates, as well as pumping stations to transport the fresh water throughout the pipeline networks. Current cost estimates for both the Marcellus and Utica projects are anticipated to total $525 million through 2023. The capital expenditures are estimated to be $250 million in 2013. The water pipeline systems are expected to deliver a reliable year-round water supply, lessen water handling costs and significantly decrease water truck traffic and associated road damage on state, county and municipal roadways. It is estimated that these water pipeline systems will reduce our well completion costs by up to $600,000 per well, and we anticipate that over 30% of our 2013 completed wells and up to 90% of our 2014 completed wells will utilize these new infrastructures. Assuming a 7,000 foot horizontal well lateral, it is estimated that 1,850 water truckload trips per well completion will be eliminated from roadways.

Due to the extensive geographic distribution of our water pipeline systems in both West Virginia and Ohio, we anticipate having the ability to offer water delivery services to neighboring oil and gas producers within and surrounding our operating area in an effort to further reduce water truck traffic.

In West Virginia, our Marcellus Shale water sourcing and delivery system infrastructure will cost an anticipated $375 million through 2023, including an estimated $200 million in 2013. Upon completion, the buried pipeline system is estimated to be 158 miles long and will extend to the Ohio River and several regional waterways for water sourcing. The water pipeline system will also include an additional 150 miles of purchased, temporary and reusable surface pipeline, 40 centralized water storage facilities equipped with transfer pumps and four other major pumping stations required for transporting water through the buried pipeline system.

In Ohio, our Utica Shale water sourcing and delivery system infrastructure will cost an anticipated $150 million through 2023, including an estimated $50 million in 2013. Upon project completion, the buried pipeline system is estimated to be 56 miles long and will rely on waterways and lakes within a close proximity to our operating area for water sourcing. The water pipeline system will also include an additional 45 miles of purchased, temporary and reusable surface pipeline and 22 centralized water storage facilities equipped with transfer pumps.

Business Strengths

Our objective is to build shareholder value through growth in reserves, production and cash flows by developing and expanding our portfolio of low-risk, high-return drilling locations and ensuring timely development of processing and pipeline takeaway capacity. We believe that the following strengths will allow us to successfully execute our business strategies:

- *Large, stable operated position in the core of the Marcellus and Utica Shales.* We own extensive and contiguous land positions in the core areas of two of the premier North American shale plays. We believe our approximately 329,000 net acres in the southwestern core of the Marcellus Shale and our 102,000 net acres in the Utica Shale are characterized by consistent and

Table of Contents

predictable geology. However, 92% of this acreage is currently undeveloped or does not include wells that have been drilled or completed to a point of producing commercially viable quantities. Approximately 52% of our Marcellus acreage and 20% of our Utica acreage was held by production at June 30, 2013, while an additional 27% and 78%, respectively, does not expire for five years or more. However, 48% and 80% of our natural gas leases related to our Marcellus and Utica acreage, respectively, require us to drill wells that are commercially productive by the end of the primary term, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. As of June 30, 2013, all of our total aggregate proved, probable and possible reserves were attributable to properties that we operate.

Multi-year, low-risk drilling inventory. Our drilling inventory at June 30, 2013 consisted of 4,576 identified potential horizontal well locations on our existing leasehold acreage. We believe that we and other operators in the area have substantially delineated and de-risked our large contiguous acreage position in the southwestern core of the Marcellus Shale. We have drilled and completed 199 wells on our Marcellus Shale acreage with a success rate of 100%. We have drilled and completed 11 horizontal wells in the core of the Utica Shale with a 100% success rate.

Exposure to large resource of liquids-rich gas and condensate. Approximately 64% of our 4,576 identified potential horizontal well locations as of June 30, 2013 target the liquids-rich gas regions of the Marcellus and Utica Shales. The gas content of this liquids-rich gas allows for NGL processing that, coupled with the condensate, can significantly improve well economics. This exposure to a range of liquids contents allows us to optimize our drilling economics across a portfolio of liquids-rich gas locations in order to take advantage of the existing commodity price environment.

Low-cost leader. We are a low-cost leader in the U.S. Our ability to drill consistently long laterals, averaging over 7,000 lateral feet, helps us to reduce costs on a per-lateral-foot basis, which is a key competitive advantage. The contiguous nature of our leasehold and the lack of geologic complexity are critical to our ability to drill long laterals. Additionally, since June 2013, we have shortened our average frac stage lengths on many of our Marcellus Shale wells from 350 feet per stage historically to 150 to 250 feet per stage. Initial well results have shown increases in 24-hour initial production rates of 25% to 35% when compared to similar wells within the same geographic area. In addition, we estimate that the incremental costs attributable to the short stage lengths has been approximately averaged an estimated $1.5 million to $2.0 million per well. We have implemented operational efficiencies to continue lowering our costs, such as (i) pad drilling, (ii) development of an extensive water pipeline system, (iii) the use of less expensive, shallow vertical drilling rigs to drill to the kick-off point of the horizontal wellbore, (iv) the use of natural gas powered rigs and (v) our proactive approach to meeting our gathering, processing and compression infrastructure needs.

Access to committed processing, compression and takeaway capacity in the Marcellus and Utica Shales. We have contracted a total of 750 MMcf/d of processing capacity in the Marcellus Shale, 400 MMcf/d of which is currently in service. Similarly, we have 300 MMcf/d of contracted processing capacity in the Utica Shale, with the option to access additional capacity. We also have secured 1,300,000 MMBtu/d of long-haul firm transportation capacity or firm sales and have committed to 20,000 Bbl/d of ethane takeaway capacity. We believe our commitment to midstream infrastructure allows us to commercialize our production more quickly at optimal prices, making us a logical consolidator of additional acreage in our core areas.

Financial strength and flexibility. As of June 30, 2013, after giving effect to this offering and the application of the net proceeds therefrom, we expect to have approximately $1.72 billion of available borrowing capacity under our credit facility (after deducting $32 million outstanding

Table of Contents

letters of credit). After the completion of this offering and the recent increase in lender commitments under our credit facility, together with our operating cash flow and hedging program, we believe we will have the financial flexibility to pursue our currently planned 2013 and 2014 development and delineation drilling activities.

Proven and incentivized executive and technical teams. We believe our management team's experience and expertise across multiple resource plays provides a distinct competitive advantage. Our officers have an average of over 30 years of industry experience in the Rocky Mountain, Midcontinent and Appalachian operating regions and have successfully built, grown and sold two unconventional resource-focused upstream companies and one midstream company in the past 15 years. Additionally, our technical team has drilled over 450 horizontal wells in the Barnett, Woodford, Marcellus and Utica Shales over the past ten years. Our management team has a significant economic interest in us through their interest in our controlling stockholder, Antero Investment. Management's percentage interest in our stock held by Antero Investment may increase over time, without diluting public investors, if our stock price appreciates following this offering. We believe our management team's ability to increase their economic interest in us provides significant incentives to grow our stock price for the benefit of all stockholders.

Business Strategy

Our strategy consists of the following principal elements:

Create shareholder value through the development of our extensive drilling inventory. Since initiating our drilling program with one rig in 2009, we have invested over $3.2 billion in land and drilling in the Appalachian Basin and currently intend to use an average of 17 rigs in 2013. With 15 rigs running in the Marcellus Shale, we are currently the most active driller in the area based on information from RigData. We intend to dedicate substantially all of our $1.45 billion drilling and completion budget in 2013 to develop our liquids-rich areas. Approximately 85% of the 2013 drilling and completion budget is allocated to the Marcellus Shale, and the remaining 15% is allocated to the Utica Shale.

Enhance returns through a focus on optimizing full cycle economics. We continually monitor and adjust our drilling program with the objective of achieving the highest total returns on our portfolio of drilling opportunities. We believe that we will achieve this objective by (i) minimizing the capital costs of drilling and completing horizontal wells, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) targeting specific BTU windows within our leasehold position to optimize our hydrocarbon mix based on the existing commodity price environment, (iv) minimizing operating costs through efficient well management, and (v) pursuing infrastructure initiatives, such as the development of our extensive water pipeline system and gas gathering system.

Maximize wellhead economics by ensuring timely development of processing and pipeline takeaway capacity and the marketing of our NGLs. We expect to continue to meaningfully increase our liquids production from the NGLs, oil and condensate associated with our growing natural gas production. We endeavor to ensure that we have sufficient processing capacity in place to recover NGLs when economically desirable. We have also secured long-term firm takeaway capacity and firm sales on major pipelines that are in existence or currently under construction in our core operating areas to accommodate our growing production and to manage basis differentials. Further, we plan to maximize the value of our NGLs through processing and marketing agreements with transporters and NGL end users.

Continue growing our core acreage position through leasing and strategic acquisitions. We intend to continue identifying and acquiring additional acreage and producing assets in our core areas in

Table of Contents

the Marcellus and Utica Shales. We believe that by managing a large team of dedicated landmen, we have a competitive advantage that enables us to continue to opportunistically add acreage to our core positions. This team of landmen has allowed us to build a large, contiguous acreage position in our Marcellus and Utica Shale plays, making us the logical acreage consolidator in our core areas. We initially targeted and acquired 114,000 net acres in the Marcellus Shale in 2008, based on specific geologic and technical analysis, and have selectively built our position to approximately 329,000 net acres. We started building our targeted Utica Shale acreage position in the fourth quarter of 2011 and currently have approximately 102,000 net acres of leasehold in the core of the liquids-rich window in Ohio.

Manage commodity price exposure through an active hedging program to protect our expected future cash flows. We expect to continue to maintain an active hedging program designed to mitigate volatility in commodity prices and regional basis differentials and to protect our expected future cash flows. As of June 30, 2013, we had entered into hedging contracts through December 31, 2018 covering a total of approximately 943 Bcfe of our projected natural gas and oil production at a weighted average price of $4.80 per Mcfe. These hedging contracts include hedges for the six-month period ending December 31, 2013 covering a total of approximately 84 Bcfe of our projected natural gas and oil production at a weighted average price of $4.68 per Mcfe. This hedging program has led to over $650 million in realized gains over the past five years.

Our Operations

Reserve Data

The information with respect to our estimated reserves presented below has been prepared in accordance with the rules and regulations of the SEC unless otherwise noted.

Reserves Presentation

Our estimated proved, probable and possible reserves and PV-10 based on SEC pricing as of December 31, 2012 and June 30, 2013 (assuming ethane recovery and ethane rejection) are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent reserve engineers, DeGolyer and MacNaughton, or D&M. Over 99% and 85% of our estimated proved, probable and possible reserves as of June 30, 2013 and December 31, 2012, respectively, were audited by D&M. See "Summary Our Properties Reserves." For each period presented, the specific percentage of our estimated reserves audited by D&M is disclosed in their summary report filed as an exhibit to the registration statement of which this prospectus forms a part. See " Preparation of Reserve Estimates" for definitions of proved, probable and possible reserves and the technologies and economic data used in their estimation.

Table of Contents

The following tables summarize our reserves and related PV-10 using SEC pricing at June 30, 2013 and December 31, 2012 assuming ethane "recovery" and ethane "rejection."

	June 30, 2013 Estimated Net Reserves (Bcfe)(1)	
	Ethane Recovery	Ethane Rejection
Estimated Proved Reserves:		
Natural gas (Bcf)	5,448	5,724
NGLs (MMBbl)	266	88
Oil (MMBbl)	5	5
Total equivalent proved reserves	7,074	6,282
Total equivalent proved developed reserves	1,590	1,445
Natural gas (Bcf)	1,276	1,327
NGLs (MMBbl)	51	18
Oil (MMBbl)	1	1
Percent proved developed	22%	23%
Total equivalent proved undeveloped reserves	5,484	4,837
Natural gas (Bcf)	4,172	4,397
NGLs (MMBbl)	215	70
Oil (MMBbl)	4	4
Percent proved undeveloped	78%	77%
PV-10 of proved reserves (in millions)(2)	$ 4,243	$ 4,468
Estimated Probable Reserves(3):		
Natural gas (Bcf)	10,416	11,366
NGLs (MMBbl)	1,009	398
Oil (MMBbl)	48	48
Total equivalent probable reserves	16,758	14,039
PV-10 of probable reserves (in millions)(2)	$ 8,223	$ 8,868
Estimated Possible Reserves(3):		
Natural gas (Bcf)	6,356	6,659
NGLs (MMBbl)	305	110
Oil (MMBbl)	18	18
Total equivalent possible reserves	8,293	7,428
PV-10 of possible reserves (in millions)(2)	$ 2,210	$ 2,413

(1) Volumes and values were determined under SEC pricing using index prices for natural gas and oil of $3.43 per MMBtu and $91.65 per Bbl. These prices were then adjusted for transportation, gathering, processing, compression and other costs. For the adjusted realized prices under SEC pricing, see " Adjusted Index Prices Used in Reserve Calculations."

(2) PV-10 was prepared using SEC pricing, discounted at 10% per annum, without giving effect to taxes or hedges. PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our reserves prior to taking into account future corporate income taxes and our current tax structure. PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a

Table of Contents

more comparable basis. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves or for proved, probable or possible reserves calculated using prices other than SEC prices. PV-10 does not take into account the effect of future taxes, and PV-10 estimates for reserve categories other than proved or for pricing sensitivities uses the relevant reserve volumes and prices, as applicable, but PV-10 is otherwise calculated using the same assumptions as those for, and in a manner consistent with, the calculation of standardized measure. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized measure of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Similarly, PV-10 estimates for price sensitivities are not adjusted for the likelihood that the relevant pricing scenario will occur, and thus they may be subject to the same issues with comparability. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved or for pricing sensitivities present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Investors should be cautioned that PV-10 does not represent an estimate of the fair market value of our proved reserves. In addition, investors should be further cautioned that estimates of PV-10 of probable reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Further, because estimates of probable and possible reserve volumes and PV-10 have not been adjusted for risk due to this uncertainty of recovery, they should not be summed arithmetically with each other or with comparable estimates for proved reserves. With respect to PV-10 calculated as of an interim date, it is not practicable to calculate the taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

The following table sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV-10), and the prices used in projecting future net cash flows at June 30, 2013:

	June 30, 2013 (In millions)
Future net cash flows	$ 14,411
Present value of future net cash flows:	
Before income tax (PV-10)	$ 4,468

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Costs are based on costs in effect for the applicable year without escalation. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reserve engineers often arrive at different estimates for the same properties.

(3) All of our estimated probable and possible reserves are classified as undeveloped.

Table of Contents

	December 31, 2012 Estimated Net Reserves (Bcfe)(1)	
	Ethane Recovery	Ethane Rejection
Estimated Proved Reserves:		
Natural gas (Bcf)	3,694	3,909
NGLs (MMBbl)	203	60
Oil (MMBbl)	3	3
Total equivalent proved reserves	4,929	4,283
Total equivalent proved developed reserves	1,047	933
Natural gas (Bcf)	828	866
NGLs (MMBbl)	36	10
Oil (MMBbl)	1	1
Percent proved developed	21%	22%
Total equivalent proved undeveloped reserves	3,882	3,350
Natural gas (Bcf)	2,866	3,043
NGLs (MMBbl)	167	50
Oil (MMBbl)	2	2
Percent proved undeveloped	79%	78%
PV-10 of proved reserves (in millions)(2)	$ 1,923	$ 1,742
Standardized measure (in millions)(3)	$ 1,601	
Estimated Probable Reserves(4):		
Natural gas (Bcf)	8,726	9,674
NGLs (MMBbl)	1,008	382
Oil (MMBbl)	22	22
Total equivalent probable reserves	14,906	12,094
PV-10 of probable reserves (in millions)(2)(3)	$ 6,583	$ 5,843
Estimated Possible Reserves(4):		
Natural gas (Bcf)	3,840	4,202
NGLs (MMBbl)	380	140
Oil (MMBbl)	31	31
Total equivalent possible reserves	6,305	5,230
PV-10 of possible reserves (in millions)(2)(3)	$ 3,161	$ 2,879

(1) Volumes and values were determined under SEC pricing using index prices for natural gas and oil of $2.78 per MMBtu and $95.05 per Bbl in the Marcellus Shale and $2.78 per MMBtu and $84.77 per Bbl in the Utica Shale. These prices were then adjusted for transportation, gathering, processing, compression and other costs. For the adjusted realized prices under SEC pricing, see "Adjusted Index Prices Used in Reserve Calculations."

(2) PV-10 was prepared using SEC pricing, discounted at 10% per annum, without giving effect to taxes or hedges. PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of future net cash flows, or after tax amount, because it presents the discounted future net cash flows attributable to our reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Moreover, GAAP does not provide a measure of estimated future

Table of Contents

net cash flows for reserves other than proved reserves or for proved, probable or possible reserves calculated using prices other than SEC prices. PV-10 does not take into account the effect of future taxes, and PV-10 estimates for reserve categories other than proved or for pricing sensitivities uses the relevant reserve volumes and prices, as applicable, but PV-10 is otherwise calculated using the same assumptions as those for, and in a manner consistent with, the calculation of standardized measure. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized measure of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Similarly, PV-10 estimates for price sensitivities are not adjusted for the likelihood that the relevant pricing scenario will occur, and thus they may be subject to the same issues with comparability. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved or for pricing sensitivities present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Investors should be cautioned that neither PV-10 nor standardized measure represents an estimate of the fair market value of our proved reserves. In addition, investors should be further cautioned that estimates of PV-10 of probable reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Further, because estimates of proved and probable reserve volumes and PV-10 have not been adjusted for risk due to this uncertainty of recovery, they should not be summed arithmetically with each other or with comparable estimates for proved reserves.

The following table sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV-10), the present value of those net cash flows after income tax (standardized measure) and the prices used in projecting future net cash flows at December 31, 2012:

	December 31, 2012
	(In millions)
Future net cash flows	$ 7,221
Present value of future net cash flows:	
Before income tax (PV-10)	$ 1,923
Income taxes	(322)
After income tax (standardized measure)	$ 1,601

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Prices for 2012 were based on 12-month unweighted average of the first-day-of-the-month pricing, without escalation. Costs are based on costs in effect for the applicable year without escalation. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reserve engineers often arrive at different estimates for the same properties.

(3) GAAP does not prescribe any corresponding GAAP measure for PV-10 of probable or possible reserves or for any pricing sensitivity scenario. As a result, it is not practicable for us to reconcile these additional PV-10 measures to GAAP standardized measure.

(4) All of our estimated probable and possible reserves are classified as undeveloped.

Table of Contents

Price Sensitivity

The following table summarizes our reserves and related PV-10 using strip pricing at June 30, 2013, assuming ethane "recovery" and ethane "rejection," in order to illustrate the sensitivity of our estimated reserves and related PV-10 to changes in product price levels based on pricing information released in the Wells Fargo Commodities Indicative Pricing Sheet. Our sensitivity analysis is limited to changes in product price levels and does not include changes to costs or the number of locations evaluated. Prices used were based on the escalating price curve for the next five years and held constant thereafter for the life of the producing properties.

Our estimated proved, probable and possible reserves and PV-10 as of June 30, 2013 based on strip pricing as of June 30, 2013 have been prepared by our internal reserve engineers, and over 99% of them were audited by our independent reserve engineers. For each period presented, the specific percentage of our estimated reserves audited by D&M is disclosed in their summary report filed as an exhibit to the registration statement of which this prospectus forms a part.

Table of Contents

Sensitivity of Reserves to Product Price Levels

	June 30, 2013 Estimated Net Reserves (Bcfe)(1)	
	Ethane Recovery	Ethane Rejection
Sensitivity of Estimated Proved Reserves Based on Strip Pricing:		
Natural gas (Bcf)	5,460	5,737
NGLs (MMBbl)	266	88
Oil (MMBbl)	5	5
Total equivalent proved reserves	7,087	6,295
Total equivalent proved developed reserves	1,594	1,448
Natural gas (Bcf)	1,279	1,330
NGLs (MMBbl)	51	18
Oil (MMBbl)	1	1
Percent proved developed	22%	23%
Total equivalent proved undeveloped reserves	5,493	4,847
Natural gas (Bcf)	4,181	4,407
NGLs (MMBbl)	215	70
Oil (MMBbl)	4	4
Percent proved undeveloped	78%	77%
PV-10 of proved reserves (in millions)(2)	$ 5,279	$ 5,644
Sensitivity of Estimated Probable Reserves Based on Strip Pricing(3):		
Natural gas (Bcf)	10,432	11,383
NGLs (MMBbl)	1,009	398
Oil (MMBbl)	48	48
Total equivalent probable reserves	16,776	14,057
PV-10 of probable reserves (in millions)(2)	$ 9,173	$ 10,210
Sensitivity of Estimated Possible Reserves Based on Strip Pricing(3):		
Natural gas (Bcf)	6,371	6,674
NGLs (MMBbl)	305	110
Oil (MMBbl)	18	18
Total equivalent possible reserves	8,310	7,444
PV-10 of possible reserves (in millions)(2)	$ 2,939	$ 3,245

(1) Volumes and values were determined under strip pricing using index prices for natural gas and oil of $3.86 per MMBtu and $87.04 per Bbl. These prices were then adjusted for transportation, gathering, processing, compression and other costs. For the adjusted realized prices under strip pricing, see " Adjusted Index Prices Used in Reserve Calculations."

(2) PV-10 was prepared using average yearly prices computed using strip pricing, discounted at 10% per annum, without giving effect to taxes or hedges. PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our reserves prior to taking into account future corporate income taxes and our current tax structure. PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Moreover, GAAP does not provide a measure

Table of Contents

of estimated future net cash flows for reserves other than proved reserves or for proved, probable or possible reserves calculated using prices other than SEC prices. PV-10 does not take into account the effect of future taxes, and PV-10 estimates for reserve categories other than proved or for pricing sensitivities uses the relevant reserve volumes and prices, as applicable, but PV-10 is otherwise calculated using the same assumptions as those for, and in a manner consistent with, the calculation of standardized measure. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized measure of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Similarly, PV-10 estimates for price sensitivities are not adjusted for the likelihood that the relevant pricing scenario will occur, and thus they may be subject to the same issues with comparability. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved or for pricing sensitivities present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Investors should be cautioned that PV-10 does not represent an estimate of the fair market value of our reserves. In addition, investors should be further cautioned that estimates of PV-10 of probable reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Further, because estimates of proved and probable reserve volumes and PV-10 have not been adjusted for risk due to this uncertainty of recovery, they should not be summed arithmetically with each other or with comparable estimates for proved reserves. With respect to PV-10 calculated as of an interim date, it is not practicable to calculate the taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

(3) All of our estimated probable and possible reserves are classified as undeveloped.

Changes in Proved Reserves During the Six Months Ended June 30, 2013

The following table summarizes the changes in our estimated proved reserves during the six months ended June 30, 2013 (in Bcfe):

Proved reserves, December 31, 2012	4,929
Extensions, discoveries, and other additions	1,982
Price and performance revisions	(553)
Sales of reserves in place	
Production	(76)
Proved reserves, June 30, 2013	6,282

Extensions, discoveries, and other additions during the six months ended June 30, 2013 of 1,982 Bcfe were added through the drillbit in the Marcellus and Utica Shales, including the addition of 210 Bcfe attributable to NGLs and oil. Upward price revisions increased proved reserves by 10 Bcfe and performance revisions increased proved reserves by 82 Bcfe. Downward price revisions decreased proved reserves by 645 Bcfe as a result of the pricing environment shifting to one that favors ethane rejection at June 30, 2013. Our estimated proved reserves as of June 30, 2013 totaled approximately 6.3 Tcfe. Our proved developed reserves increased to 1,445 Bcfe at June 30, 2013.

Table of Contents

Changes in Proved Reserves During 2012

The following table summarizes the changes in our estimated proved reserves during 2012 (in Bcfe):

Proved reserves, December 31, 2011	5,017
Extensions, discoveries, and other additions	1,951
Price and performance revisions	222
Sales of reserves in place(1)	(2,174)
Production	(87)
Proved reserves, December 31, 2012	4,929

(1) Includes 2012 production from Arkoma and Piceance Basins of 35 Bcfe.

Extensions, discoveries, and other additions during 2012 of 1,951 Bcfe were added through the drillbit in the Marcellus and Utica Shales, including the addition of 709 Bcfe attributable to NGLs and oil. Downward price revisions resulted in a reduction of proved reserves of 102 Bcfe and performance revisions increased proved reserves by 324 Bcfe. Sales of proved reserves of 2,174 Bcfe resulted from the sale of our Arkoma and Piceance Basin properties. Our estimated proved reserves as of December 31, 2012 totaled approximately 4.9 Tcfe. Our proved developed reserves increased year over year by 24% to 1,047 Bcfe at December 31, 2012.

Adjusted Index Prices Used in Reserve Calculations

The following tables show our index prices used in our reserve calculations as of the dates indicated under both SEC pricing and strip pricing:

	June 30, 2013	
	Marcellus	**Utica**
SEC Pricing:		
Natural gas (per MMBtu)	$ 3.43	$ 3.43
Oil (per Bbl)	$ 91.65	$ 91.65
Strip Pricing:		
Natural gas (per MMBtu)	$ 3.86	$ 3.86
Oil (per Bbl)	$ 87.04	$ 87.04

	December 31, 2012	
	Marcellus	**Utica**
SEC Pricing:		
Natural gas (per MMBtu)	$ 2.78	$ 2.78
Oil (per Bbl)	$ 95.05	$ 95.05

The following table shows the product price levels used to determine the relevant average index price under strip pricing based on pricing information released in the Wells Fargo Commodities Indicative Pricing Sheet. These price levels have not been adjusted for transportation, gathering, processing, compression or other costs.

	2013	**2014**	**2015**	**2016**	**2017**	**Thereafter**
TCO Gas Price (per MMBtu)	$ 3.48	$ 3.69	$ 3.90	$ 4.05	$ 4.19	$ 4.19
App Oil Price (per Bbl)	$ 95.37	$ 90.42	$ 85.76	$ 82.76	$ 80.88	$ 80.88

Table of Contents

The following tables show our index prices, as adjusted for gathering, processing, compression and other costs, and used in our reserve calculations as of the dates indicated under both SEC pricing and strip pricing and assuming ethane "recovery" and ethane "rejection":

	June 30, 2013					
	Ethane Recovery			Ethane Rejection		
	Marcellus	Upper Devonian	Utica	Marcellus	Upper Devonian	Utica
SEC Pricing:						
Proved Reserves:						
Natural gas (per Mcf)	$ 3.00	$ 3.12	$ 2.77	$ 3.01	$ 3.12	$ 3.11
NGLs (per Bbl)	$ 17.82		$ 23.43	$ 45.66		$ 48.80
Oil (per Bbl)	$ 81.65		$ 81.14	$ 81.65		$ 81.14
Probable Reserves:						
Natural gas (per Mcf)	$ 3.06	$ 3.09	$ 2.75	$ 3.09	$ 3.09	$ 3.10
NGLs (per Bbl)	$ 21.54	$ 14.70	$ 21.64	$ 46.98	$ 44.06	$ 48.12
Oil (per Bbl)	$ 81.65		$ 81.05	$ 81.65		$ 81.05
Possible Reserves:						
Natural gas (per Mcf)	$ 3.01	$ 2.86	$ 3.07	$ 3.01	$ 2.97	$ 3.23
NGLs (per Bbl)	$ 24.95	$ 16.77	$ 22.04	$ 47.85	$ 45.25	$ 48.12
Oil (per Bbl)	$ 81.65	$ 81.65	$ 81.06	$ 81.65	$ 81.65	$ 81.06
Strip Pricing Sensitivity Case:						
Sensitivity of Proved Reserves Based on Strip Pricing:						
Natural gas (per Mcf)	$ 3.75	$ 3.91	$ 3.39	$ 3.76	$ 3.91	$ 3.78
NGLs (per Bbl)	$ 15.43		$ 19.80	$ 37.93		$ 40.66
Oil (per Bbl)	$ 72.06		$ 74.42	$ 72.06		$ 74.42
Sensitivity of Probable Reserves Based on Strip Pricing:						
Natural gas (per Mcf)	$ 3.86	$ 3.90	$ 3.08	$ 3.89	$ 3.90	$ 3.89
NGLs (per Bbl)	$ 18.44	$ 12.78	$ 18.35	$ 39.01	$ 37.21	$ 39.87
Oil (per Bbl)	$ 71.13		$ 72.17	$ 71.13		$ 72.17
Sensitivity of Possible Reserves Based on Strip Pricing:						
Natural gas (per Mcf)	$ 3.79	$ 3.63	$ 3.63	$ 3.79	$ 3.76	$ 4.03
NGLs (per Bbl)	$ 21.18	$ 14.63	$ 18.69	$ 39.73	$ 36.96	$ 39.78
Oil (per Bbl)	$ 70.89	$ 70.88	$ 70.70	$ 70.89	$ 70.88	$ 70.66

Table of Contents

	December 31, 2012			
	Ethane Recovery		Ethane Rejection	
	Marcellus	Utica	Marcellus	Utica
SEC Pricing:				
Proved Reserves:				
Natural gas (per Mcf)	$ 1.99	$ 2.08	$ 2.17	$ 2.37
NGLs (per Bbl)	$ 26.36	$ 28.81	$ 48.88	$ 53.87
Oil (per Bbl)	$ 85.05	$ 84.47	$ 85.05	$ 84.47
Probable Reserves:				
Natural gas (per Mcf)	$ 2.06	$ 2.08	$ 2.32	$ 2.37
NGLs (per Bbl)	$ 26.48	$ 28.48	$ 51.60	$ 54.12
Oil (per Bbl)	$ 85.05	$ 84.47	$ 85.05	$ 84.47
Possible Reserves:				
Natural gas (per Mcf)	$ 2.12	$ 2.13	$ 2.27	$ 2.40
NGLs (per Bbl)	$ 26.36	$ 25.56	$ 51.45	$ 51.84
Oil (per Bbl)	$ 85.05	$ 84.47	$ 85.05	$ 84.47

Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in our estimated proved undeveloped reserves during 2012 (in Bcfe):

Proved undeveloped reserves, December 31, 2011	4,173
Conversions into proved developed reserves	(377)
Extensions, discoveries, and other additions	1,692
Price and performance revisions	144
Sales of reserves in place	(1,750)
Proved undeveloped reserves, December 31, 2012	3,882

Extensions, discoveries, and other additions during 2012 of 1,692 Bcfe proved undeveloped reserves were added through the drillbit in the Marcellus and Utica Shales, including the addition of 613 Bcfe attributable to NGLs and oil. Downward price revisions resulted in a reduction of proved undeveloped reserves by 95 Bcfe and performance revisions increased proved undeveloped reserves by 239 Bcfe. Sales of proved undeveloped reserves of 1,750 Bcfe resulted from the sale of our Arkoma and Piceance Basin properties. Our estimated proved undeveloped reserves as of December 31, 2012 totaled approximately 3.9 Tcfe.

We incurred costs of approximately $396 million in 2012 to convert 377 Bcfe of proved undeveloped reserves to proved developed reserves in 2012. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2012 are approximately $3.3 billion over the next five years, which we expect to finance through the proceeds of this offering, cash flow from operations, borrowings under our credit facility, sales of non-core assets and other sources of capital financing. Our drilling programs to date have focused on proving our undeveloped leasehold acreage through delineation drilling. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also focus on drilling our proved undeveloped reserves. All of our proved undeveloped reserves are expected to be developed over the next five years. See "Risk Factors Risks Related to Our Business The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

Table of Contents

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2012, 2011 and 2010 and June 30, 2013 included in this prospectus were prepared by our internal reserve engineers in accordance with petroleum engineering and evaluation standards published by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Certain of the internally prepared reserve estimates were audited by our independent reserve engineers. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. The technical persons responsible for overseeing the audit of our reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserve auditing process. Periodically, our technical team meets with the independent reserve engineers to review properties and discuss methods and assumptions used by us to prepare reserve estimates. Our internally prepared reserve estimates and related reports are reviewed and approved by our Vice President of Reserves, Planning & Midstream, Ward D. McNeilly, and our Vice President of Production, Kevin J. Kilstrom. Mr. McNeilly has been with the Company since October 2010. Mr. McNeilly has 34 years of experience in oil and gas operations, reservoir management, and strategic planning. From 2007 to October 2010 Mr. McNeilly was the Operations Manager for BHP Billiton's Gulf of Mexico operations. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. From 1979 through 1996 Mr. McNeilly served in various domestic and international operations and reservoir and asset management positions with Amoco. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

Mr. Kilstrom has served as Vice President of Production since June 2007. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2006 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an Operations Manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999 where he served in various operating roles with a focus on unconventional resources. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University. Our senior management also reviews our reserve estimates and related reports with Mr. McNeilly and Mr. Kilstrom and other members of our technical staff. Additionally, our senior management reviews and approves any internally estimated significant changes to our proved reserves on a quarterly basis.

Proved reserves are reserves 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 under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, micro-seismic data and well-test data. Probable reserves are reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us. Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

Methodology Used to Apply Reserve Definitions

In the Marcellus Shale, our estimated reserves are based on information from our large, operated proved developed producing reserve base, as well as public information from other operators in the area, which can be used to confirm or supplement our internal estimates. Typically, proved undeveloped properties are booked based on applying the estimated lateral length to the average Bcf per 1,000 feet from our proved developed producing wells.

We may attribute up to 11 proved undeveloped locations based on one proved developed producing well where analysis of geologic and engineering data can be estimated with reasonable certainty to be commercially recoverable. However, the ratio of proved undeveloped locations generated will be lower when multiple proved developed wells are drilled on a single pad. In addition, we have applied the concept of a Highly-Developed Area, or HDA, to certain areas of our Marcellus Shale acreage whereby undeveloped properties are booked as proved reserves so long as well count is sufficient for statistical analysis and certain land, geologic, engineering and commercial criteria are met, including sufficient proved developed producing results and a geologically continuous and consistent reservoir.

Locations for probable reserves are booked within a three-mile radius of existing Marcellus Shale production where analysis of geologic and engineering data suggests these locations are more likely than not to be recovered. Possible locations are booked outside the scope of the three-mile probable radius.

Although our operating history in the Utica Shale is more limited than our Marcellus Shale operations, we expect to be able to apply a similar methodology once the well count is sufficient for statistical analysis. The primary differences between the two areas are that (i) we have not established an HDA in the Utica Shale and (ii) each proved developed producing well in the Utica Shale is only able to generate four direct offset well locations in the Utica Shale due to less relative maturity.

Identification of Potential Well Locations

Our identified potential well locations include locations to which proved, probable or possible reserves were attributable based on SEC pricing as of June 30, 2013 and December 31, 2012.

Our identified potential well locations to which proved, probable or possible reserves were attributable are identified in accordance with the methodology described in " Methodology Used to Apply Reserve Definitions." Our locations that were uneconomic based on SEC pricing as of June 30, 2013 include 89 locations in the Marcellus Shale, 86 locations in the Utica Shale and 185 in the Upper Devonian Shale. Our identified potential well locations prospective for the Utica Shale dry gas include 950 potential locations as of June 30, 2013.

Production, Revenues and Price History

Natural gas, NGLs, and oil are commodities; therefore, the price that we receive for our production is largely a function of market supply and demand. While demand for natural gas in the United States has increased dramatically since 2000, natural gas and NGL supplies have also increased

Table of Contents

significantly as a result of horizontal drilling and fracture stimulation technologies which have been used to find and recover large amounts of oil and natural gas from various shale formations throughout the United States. Demand is impacted by general economic conditions, weather and other seasonal conditions. Over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas reserves that may be economically produced and our ability to access capital markets. See "Risk Factors Risks Related to Our Business Natural gas prices are volatile. A substantial or extended decline in natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

The following table sets forth information regarding our production, our revenues and realized prices, and production costs from continuing operations in the Appalachian Basin for the years ended December 31, 2010, 2011 and 2012 and for the three and six months ended June 30, 2012 and 2013. For additional information on price calculations, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Continuing Operations Data Appalachian Basin

	Year Ended December 31,			Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2011**	**2012**	**2012**	**2013**	**2012**	**2013**
Production data:							
Natural gas (Bcf)	11	45	87	19	39	35	73
NGLs (MBbl)			71		354		559
Oil (MBbl)		2	19	4	25	4	35
Total combined production (Bcfe)	11	45	87	19	42	35	76
Average daily combined production (MMcfe/d)	30	124	239	213	458	195	421
Average sales prices:							
Natural gas (per Mcf)	$ 4.39	$ 4.33	$ 2.99	$ 2.31	$ 4.37	$ 2.53	$ 4.05
NGLs (per Bbl)	$	$	$ 52.07	$	$ 48.70	$	$ 49.75
Oil (per Bbl)	$	$ 97.19	$ 80.34	$ 77.16	$ 85.07	$ 80.05	$ 85.36
Combined average sales prices before effects of cash settled derivatives (per Mcfe)(1)	$ 4.39	$ 4.33	$ 3.03	$ 2.32	$ 4.60	$ 2.54	$ 4.27
Combined average sales prices after effects of cash settled derivatives (per Mcfe)(1)	$ 5.78	$ 5.44	$ 5.08	$ 4.90	$ 4.94	$ 5.26	$ 5.09
Average costs per Mcfe:							
Lease operating costs	$ 0.11	$ 0.10	$ 0.07	$ 0.10	$ 0.03	$ 0.07	$ 0.03
Gathering, compression, processing and transportation	$ 0.85	$ 0.83	$ 1.04	$ 1.04	$ 1.17	$ 0.89	$ 1.18
Production taxes	$ 0.27	$ 0.26	$ 0.23	$ 0.17	$ 0.24	$ 0.20	$ 0.25
Depreciation, depletion, amortization and accretion	$ 1.71	$ 1.24	$ 1.17	$ 1.15	$ 1.27	$ 1.08	$ 1.23
General and administrative	$ 2.03	$ 0.74	$ 0.52	$ 0.54	$ 0.33	$ 0.55	$ 0.35

(1) Average sales prices shown reflect both of the before and after effects of our cash settled derivatives. Our calculation of such effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges.

Table of Contents

Discontinued Operations Data Arkoma and Piceance Basins

The table above does not include the following production or revenue from discontinued operations from the Arkoma and Piceance Basin properties which were sold in 2012:

	Year Ended December 31,		
	2010	**2011**	**2012**
Production (combined Bcfe)	36	44	35
Natural gas, NGL and oil production revenues (in millions)	$ 159	$ 197	$ 125

Productive Wells

As of June 30, 2013, we had a total of 416 gross (380 net) producing wells, averaging a 91% working interest. This well count includes 243 gross and 214 net shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions. Our wells are natural gas wells, many of which also produce oil, condensate and NGLs. We do not have interests in any wells that only produce oil or NGLs.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of June 30, 2013. Approximately 52% of our Marcellus acreage and 20% of our Utica acreage was held by production at June 30, 2013. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
Basin	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Marcellus	27,078	26,648	374,851	293,764	401,929	320,412
Utica	1,971	1,597	121,746	98,721	123,717	100,318
Total	29,049	28,245	496,597	392,485	525,646	420,730

Undeveloped Acreage Expirations

The following table sets forth the number of total gross and net undeveloped acres as of June 30, 2013 that will expire in 2013, 2014 and 2015 in the Marcellus Shale unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such acreage is extended or renewed.

	Gross	**Net**
2013	9,844	7,857
2014	11,517	5,861
2015	25,669	18,046

As of June 30, 2013, we had less than 100 net acres of leasehold in the Utica Shale that will expire over the next three years.

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2010, 2011 and 2012 and the six months ended June 30, 2013. Gross wells reflect the sum of all wells in which we

Table of Contents

own an interest and includes historical drilling activity in the Appalachian, Arkoma and Piceance Basins. Net wells reflect the sum of our working interests in gross wells.

	Year Ended December 31,						Six Months Ended June 30,	
	2010		2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells:								
Productive	128	24	135	65	107	92	36	35
Dry								
Total development wells	128	24	135	65	107	92	36	35
Exploratory wells:								
Productive	56	22	74	30	30	24	33	32
Dry	11	5						
Total exploratory wells	67	27	74	30	30	24	33	32

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell gas. We believe we will have sufficient production quantities to meet such commitments, but may be required to purchase gas from third parties to satisfy shortfalls should they occur.

As of June 30, 2013, our firm sales commitments through 2017 included:

Year Ending December 31,	Volume of Natural Gas (MMcfe/d)
2013	260
2014	430
2015	420
2016	388
2017	212

In addition, we have firm transportation contracts that require us to deliver products to pipeline transporters or pay demand charges for shortfalls. The minimum demand fees are reflected in our table of contractual obligations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Debt Agreements and Contractual Obligations."

Major Customers

For the year ended December 31, 2012, sales to South Jersey Resources Group, LLC, Nextera Energy Powermarketing LLC and Dominion Filed Services Inc. represented 23%, 13% and 10% of our total sales, respectively. For the year ended December 31, 2011, sales from our top three customers accounted for 28%, 17%, and 12% of our total sales, respectively. For the year ended December 31, 2010, sales from our top three customers accounted for 23%, 13% and 11% of our total sales, respectively. Although a substantial portion of production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business, as other customers or markets would be accessible to us.

Table of Contents

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under natural gas leases; or
- net profits interests.

Seasonality

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing natural gas and oil properties have statutory provisions regulating the exploration for and production of natural gas and oil, including provisions related to permits for the drilling of wells,

Table of Contents

bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the FERC, and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Natural Gas and Oil

The production of natural gas and oil is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

We own interests in properties located onshore in three U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Table of Contents

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act, or NGPA, and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

Beginning in 1992, FERC issued a series of orders to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been greatly reduced and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The Domenici Barton Energy Policy Act of 2005, or EP Act of 2005, is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

On November 20, 2008, FERC issued Order 720, a final rule on the daily scheduled flow and capacity posting requirements. Under Order 720, major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtus of gas over the previous three calendar years, are required to post daily certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu per day and interstate pipelines are required to post information regarding the provision of no-notice service. In October 2011, Order 720, as clarified, was vacated by the Court of Appeals for the Fifth Circuit with respect to its application to non-interstate pipelines. In December 2011, the Fifth Circuit confirmed that Order 720, as clarified, remained applicable to interstate pipelines with respect to posting information regarding the provision of no-notice service.

We cannot accurately predict whether FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act, or CEA, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly

Table of Contents

delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our natural gas and oil exploration and production operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or other regulated activity commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits, establish specific safety and health criteria addressing worker protection and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act, or the NEPA. NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an Environmental Assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study, or EIS, that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay or limit, or increase the cost of, the development of natural gas and oil projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict 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. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances but we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act, or RCRA, and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that are regulated as hazardous wastes. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and

Table of Contents

wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Obtaining permits has the potential to delay the development of natural gas and oil projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We believe that we maintain all required discharge permits necessary to conduct our operations, and further believe we are in substantial compliance with the terms thereof. We are currently undertaking a review of recently acquired natural gas properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, on August 16, 2012, the EPA published final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed.

Table of Contents

EPA intends to issue revised rules in 2013 that are likely responsive to some of these requests. For example, on April 12, 2013 EPA published a proposed amendment extending compliance dates for certain storage vessels. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas and oil projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic event; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure through a cased and cemented wellbore into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations as does most of the domestic oil and natural gas industry. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced

Table of Contents

its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a draft final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. Other governmental agencies, including the U.S. Department of Energy have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the applicable worker health and safety requirements.

Endangered Species Act

The federal Endangered Species Act, or ESA, was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on natural gas and oil leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for natural gas and oil development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2012, nor do we anticipate that such expenditures will be material in 2013.

Employees

As of June 30, 2013, we had 184 full-time employees, including 14 in executive, finance, treasury and administration, 18 in geology, 56 in production and engineering, 22 in accounting, 60 in land, and 14 in midstream. We also employed approximately 163 contract personnel who assist our full-time employees with specific tasks. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

Legal Proceedings

We are party to various legal proceedings and claims in the ordinary course of our business. We believe certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on our consolidated financial position, results of operations or liquidity.

In March 2011, we received orders for compliance from federal regulatory agencies, including the EPA, relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non-compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. We have responded to all pending orders and are actively cooperating with the relevant agencies. No fine or penalty relating to these matters has been proposed at this time, but we believe that these actions will result in monetary sanctions exceeding $100,000. In addition, we expect to incur additional costs to remediate these well locations in order to bring them into compliance with applicable environmental laws and regulations. We have not, however, been required to suspend our operations at these locations to date and our management team does not expect these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Table of Contents

MANAGEMENT

Directors and Executive Officers

The following table sets forth names, ages and titles of our directors, director nominees and executive officers as of June 30, 2013.

Name	Age	Title
Peter R. Kagan	45	Director
W. Howard Keenan, Jr.	62	Director
Christopher R. Manning	45	Director
Richard W. Connor	64	Director
Robert J. Clark	68	Director Nominee
Benjamin A. Hardesty	63	Director Nominee
James R. Levy	37	Director Nominee
Paul M. Rady	59	Chairman of the Board of Directors and Chief Executive Officer
Glen C. Warren, Jr.	57	Director, President, Chief Financial Officer and Secretary
Kevin J. Kilstrom	58	Vice President Production
Alvyn A. Schopp		