Rice Energy Inc.
Form 10-K
March 13, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2014
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from_______ to_______
Commission File Number: 001-36273
Rice Energy Inc.
(Exact name of registrant as specified in its charter)

Delaware	46-3785773
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
400 Woodcliff Drive Canonsburg, Pennsylvania	15317
(Address of principal executive offices)	(Zipcode)

Registrant's telephone number, including area code: (724) 746-6720

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. þYes ¨No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ¨Yes þNo

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

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
¨Yes þNo

The aggregate market value of the equity held by non-affiliates of the registrant as of June 30, 2014: $1,612,534,986
The number of shares of common stock outstanding as of March 10, 2015: 136,297,909
Documents Incorporated by Reference
The Company’s definitive proxy statement relating to the annual meeting of shareholders (to be held June 3, 2015) will be filed with the Commission within 120 days after the close of the Company’s fiscal year ended December 31, 2014 and is incorporated by reference in Part III to the extent described herein.

RICE ENERGY INC.
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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 that are not emerging growth companies under the JOBS Act, we are not 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;
- provide certain disclosure regarding executive compensation required of larger public companies or hold shareholder advisory votes on executive compensation required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"); 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 fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30);
- 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 of 1933, as amended, or the "Securities Act," for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

Cautionary Statement Regarding Forward-Looking Statements

This Annual Report on Form 10-K (the "Annual Report") contains "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and income/losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looki 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 "Item 1A. Risk Factors" included in this Annual Report.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas, natural gas liquid ("NGL") 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 Annual Report 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 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 "Item 1A. Risk Factors" in this Annual Report.

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 could 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 Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report 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 Annual Report.

Commonly Used Defined Terms

As used in the Annual Report, unless the context indicates or otherwise requires, the following terms have the following meanings:

- “Rice Energy,” the “Company,” “we,” “our,” “us” or like terms refer collectively to Rice Energy Inc. and its consolidated subsidiaries, including Rice Drilling B LLC;
- “Rice Drilling B” refers to Rice Drilling B LLC, a wholly-owned subsidiary of Rice Energy;
- “Rice Partners” refers to Rice Energy Family Holdings, LP (formerly known as Rice Energy Limited Partners), an entity affiliated with members of the Rice family;
- “Rice Holdings” refers to Rice Energy Holdings LLC;
- “RMP” refers to Rice Midstream Partners LP (NYSE: RMP);
- “Rice Midstream OpCo” refers to Rice Midstream OpCo LLC, a wholly-owned subsidiary of RMP;
- “Midstream Holdings” refers to Rice Midstream Holdings LLC, a wholly-owned subsidiary of Rice Energy;
- “Rice Appalachia” refers to Rice Energy Appalachia, LLC, the parent company of Rice Drilling B prior to our initial public offering;
- “Alpha Holdings” refers to Foundation PA Coal Company, LLC, a wholly-owned indirect subsidiary of Alpha Natural Resources, Inc.;
- “Marcellus joint venture” refers collectively to Alpha Shale Resources, LP and its general partner, Alpha Shale Holdings, LLC;
- “Natural Gas Partners” refers to a family of private equity investment funds organized to make direct equity investments in the energy industry, including the funds invested in us; and
- “NGP Holdings” refers to NGP Rice Holdings, LLC.

PART I

Item 1. Business

General

Rice Energy Inc., a Delaware corporation, is an independent natural gas and oil company engaged in the acquisition, exploration and development of natural gas, oil and NGL properties in the Appalachian Basin. We operate in two business segments, which are managed separately due to their distinct operational differences. Our two reporting segments are as follows:

Exploration and Production - This segment is engaged in the acquisition, exploration and development of natural gas, oil and NGLs.

Midstream - This segment is engaged in the gathering and compression of natural gas, oil and NGL production of, and in the provision of water services to support the well completion activities of Rice Energy and third-parties.

Our corporate offices are located at 400 Woodcliff Drive, Canonsburg, Pennsylvania 15317 (telephone: (724) 746-6720). Our common stock is listed and traded on the New York Stock Exchange (the “NYSE”) under the symbol “RICE.” At December 31, 2014, we had 136,280,766 shares outstanding.

Significant Accomplishments in 2014

- Completed successful Rice Energy initial public offering (“IPO”), providing $593.6 million of net proceeds
- Strategically acquired Marcellus Shale gas gathering assets for $111.4 million
- Issued $900.0 million of senior notes due 2022 at 6.25%
- Produced 97.7 Bcfe during 2014, a 325% increase above 2013 production
- Proved reserves increased 242% to 1.3 Tcfe, compared to year end 2013
- Completed first Utica Shale well, which tested at 42 MMcfe/d
- Opportunistically acquired approximately 22,000 net acres in Greene County, Pennsylvania in August 2014, partially funded with net proceeds of $196.3 million from our follow on equity offering
- Significantly expanded leasehold position by 57% to approximately 141,000 net acres as of year end 2014
- Completed successful initial public offering of Rice Midstream Partners LP (NYSE: RMP) in December 2014 providing net proceeds of $444.1 million

Background on Our Financial Information and Results of Operations

On January 29, 2014, we completed our IPO and related transactions, including our reorganization and concurrent acquisition of Alpha Holdings’ 50% interest in our Marcellus joint venture. On December 22, 2014, RMP completed its IPO and related transactions, including our contribution to it of certain gas gathering and compression assets.

As a result of the reorganziations that occurred during 2014, our historical financial condition and results of operations for the periods presented in this Annual Report may not be comparable, either from period to period or going forward. For example, information for the period from January 1, 2014 until January 29, 2014, as contained within the year ended December 31, 2014, and for the years ended December 31, 2013 and 2012, pertain to the historical financial statements and results of operations of our accounting predecessor. Such periods reflect only our 50% equity investment in our Marcellus joint venture. From and after our acquisition of the remaining 50% interest from Alpha Holdings on January 29, 2014, the results of operations of our Marcellus joint venture are consolidated into our results of operations.

In connection with the RMP IPO in December 2014, we contributed all of our gas gathering and compression assets in Washington and Greene Counties, Pennsylvania in exchange for, among other things, common and subordinated units representing a 50.0% limited partner interest and all of the incentive distribution rights in RMP. Indirectly through Midstream Holdings, we own and control the general partner of RMP, and as such the results of operations of RMP are consolidated into our results of operations. However, while our results of operations consolidate the results of operations of RMP, for the period from December 22, 2014 until December 31, 2014, as contained within the year ended December 31, 2014, they give effect to the noncontrolling interest in RMP held by its public unitholders.

Also in connection with the RMP IPO, we entered into various gas gathering and compression agreements and water distribution services agreements, both intercompany and, in the case of certain gas gathering and compression services in Pennsylvania, with RMP. Prior to December 22, 2014, with certain limited exceptions, our Midstream segment did not charge fees for providing such services to our Exploration and Production segment.

Exploration and Production Business Segment

Our Exploration and Production segment operates in what we believe to be the core of the Marcellus and Utica Shales. As of December 31, 2014, we held approximately 86,000 net acres in the southwestern core of the Marcellus Shale, substantially all of which are in Washington and Greene Counties, Pennsylvania. We established our Marcellus Shale acreage position through a combination of largely contiguous acreage acquisitions in 2009 and 2010 and through numerous bolt-on acreage acquisitions. In 2012, we acquired approximately 33,000 of our 55,000 net acres in the southeastern core of the Utica Shale, primarily in Belmont County, Ohio. We believe this area to be the core of the Utica Shale based on our and publicly available drilling results. We operate a substantial majority of our acreage in the Marcellus Shale and a majority of our acreage in the Utica Shale.

The following table provides a summary of our approximate net acreage, net drilling locations and net producing wells as of December 31, 2014, average net daily production for the three months ended December 31, 2014, projected 2015 net wells online and projected 2015 drilling and completion ("D&C") capital budget as of March 12, 2015:

	Approximate Net Acreage	Net Drilling Locations (1)	Net Producing Wells	Q4 2014 Average Net Daily Production (MMcfe/d)	2015 Projected Net Wells Online	2015 Projected D&C Capex Budget ($mm)
Marcellus Shale	86,000	495	78	336	26	$340
Utica Shale (2)	55,000	356	7	58	10 (3)	220
Upper Devonian Shale	77,000	382	3	3	—	—
Total (4)	141,000	1,233	88	397	36	$560

(1) Based on our reserve report as of December 31, 2014, we had 62 net drilling locations in the Marcellus Shale associated with proved undeveloped reserves and 10 net drilling locations in the Marcellus Shale associated with proved developed not producing reserves and we had four net drilling locations in the Utica Shale associated with proved undeveloped reserves and one net drilling location in the Utica Shale associated with proved developed not producing reserves. Please see "Item 2. Properties—Exploration and Production Properties Reserve Data—Determination of Drilling Locations" for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see "Item 1A. Risk Factors—Risks Related to Our Business—Our drilling 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 drilling locations."

(2) Utica Shale net drilling locations gives effect to our projected 61.8% working interest in the Utica Shale after applying unitization and participating interest assumptions described under "Item 2. Properties—Exploration and Production Properties Reserve Data—Determination of Drilling Locations."

(3) Includes one Utica Shale well in Pennsylvania.

(4) The 77,000 net acres in the Upper Devonian Shale is not included in the total acreage as the Upper Devonian and the Marcellus Shale are stacked formations within the same geographic footprint.

The following table provides certain operational data related to our proved developed producing Marcellus wells as of December 31, 2014. We are the operator of each of these wells.

Year(s)	Gross Operated Wells Turned Into Sales	Average Lateral Length (Feet)	Periodic Flow Rates (MMcfe/d) (1) 0-90	91-180	181-360	361-720	D&C ($/Foot) (2)
2010-2011	6	3,281	5.7	6.0	4.4	2.7	$2,377
2012	9	5,731	9.2	10.0	6.8	4.2	1,660
2013	22	6,286	11.2	10.6	7.6	5.9	1,476
2014 (3)	41	7,282	11.2	10.3	5.8	N/A	1,176
Total	78	6,515	10.5	9.9	6.8	3.8	$1,409

(1) Based on production data through March 1, 2015.
(2) D&C costs are shown gross of our working interest's proportionate share.
(3) Excludes seven producing wells acquired in our Greene County, Pennsylvania acreage acquisition in August 2014.

Additionally, we have drilled and completed three Upper Devonian horizontal wells on our Marcellus Shale acreage with a 100% success rate. Based on our Upper Devonian wells and those of other operators in the vicinity of our acreage as well as other geologic data, we estimate that a substantial majority of our Marcellus Shale acreage in southwestern Pennsylvania is prospective for the slightly shallower Upper Devonian Shale. As of December 31, 2014, we had 382 net drilling locations in the Upper Devonian Shale.

We applied the same shale analysis and acquisition strategy that we developed and employed in the Marcellus Shale to acquire our acreage in the Utica Shale in Ohio. In June 2014, we completed our first Utica well in Belmont County, the Bigfoot 9H. As of December 31, 2014, the Bigfoot 9H had cumulatively produced 2.8 Bcf of natural gas. In early December, we increased the restricted flow rate to approximately 16 MMcfe/d from 14 MMcfe/d. During the third quarter of 2014, we turned two additional operated Utica wells into sales at a restricted rate of 16 MMcfe/d. As of December 31, 2014, we had 23 gross (7 net) Utica wells producing, including 3 gross (2 net) operated wells. As of December 31, 2014, we had 356 net Utica Shale drilling locations.

During 2014, we turned 44 gross (39 net) wells into sales and achieved record sales volumes of 97,737 MMcfe, representing a 325% increase in production over the prior year. In addition, we increased our leasehold position in the Marcellus and Utica Shales to approximately 86,000 and 55,000 net acres as of December 31, 2014, representing a 98% and 18% increase over the prior year, respectively. We achieved this growth in acreage through organic leasing efforts, our January 2014 acquisition of the remaining 50% interest in our Marcellus joint venture in exchange for total consideration in the form of cash and stock of $322 million and our August 2014 acquisition of approximately 22,000 net acres and 12 developed (7 producing) wells in the Marcellus Shale in Greene County, Pennsylvania for approximately $329.5 million. As of December 31, 2014, we had 1,306.6 Bcfe of proved reserves (49% proved developed and 100% natural gas), representing a 117% increase over the prior year.

In 2015, we plan to invest $680.0 million in our Exploration and Production segment as follows:

- $340.0 million for drilling and completion in the Marcellus Shale;
- $220.0 million for drilling and completion in the Utica Shale; and
- $120.0 million for leasehold acquisitions.

Our capital budget excludes acquisitions, other than leasehold acquisitions. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

As of March 1, 2015, our average annual firm transportation contracts and firm sales arrangements are approximately 813,000 MMBtu/d in 2015, 918,000 MMBtu/d in 2016 and 1,011,000 MMBtu/d in 2017. These amounts include approximately 115,000 MMBtu/d of firm sales contracted with a third party through October 2017, subject to annual renewal. Under firm transportation contracts, we are obligated to pay demand charges for the contracted capacity regardless of whether it is utilized. We continue to actively identify and evaluate additional takeaway capacity to facilitate production growth in our Appalachian Basin position.

In October 2013, we entered into a Development Agreement and an AMI Agreement with Gulfport Energy Corporation ("Gulfport") covering approximately 50,000 aggregate net acres in the Utica Shale in Belmont County, Ohio. We refer to these agreements as our "Utica Development Agreements." Pursuant to the Utica Development Agreements, we have an approximately 68.7% participating interest in acreage currently owned or to be acquired by us or Gulfport located within Goshen and Smith Townships (the "Northern Contract Area") and approximately 48.2% participating interest in acreage currently owned or to be acquired by us or Gulfport located within Wayne and Washington Townships (the "Southern Contract Area"), each within Belmont County, Ohio. The remaining participating interests are held by Gulfport. The participating interests of us and Gulfport in each of the Northern and Southern Contract Areas approximate our current relative acreage positions in each area.

Pursuant to the Development Agreement, we are named the operator (or Gulfport will agree to vote in favor of our operatorship) of drilling units located in the Northern Contract Area, and Gulfport is named the operator (or we will agree to vote in favor of its operatorship) of drilling units located in the Southern Contract Area. Upon development of a well on the subject acreage, we and Gulfport will convey to one another, pursuant to a cross conveyance, a working interest percentage equal to the amount of the underlying working interest multiplied by the applicable participating interest. As wells are developed in the respective contract area, our average working interests in the Utica Shale will decrease as the applicable participating interests are applied to the developed wells.

For the year ended December 31, 2014, our Exploration and Production segment represented 99% of our operating revenues.

Midstream Business Segment

Our Midstream segment invests in infrastructure to complement our Exploration and Production activities. Through ownership and operation of this infrastructure, we are able to improve our ability to manage costs, control the timing of bringing new production online, and enhance the value received for gathering and compressing our production and providing water services to our well completions operations. 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.

Following the completion of its initial public offering on December 22, 2014, our midstream activities include Rice Midstream Partners LP (NYSE: RMP), which is a publicly traded limited partnership formed to own, operate, develop and acquire midstream assets in the Appalachian Basin and which currently owns our Washington and Greene County gas gathering systems. At December 31, 2014, we owned an approximate 50% limited partner interest and all of the incentive distribution rights in RMP, whose results are consolidated in our financial statements. Unless otherwise noted, discussions of our Midstream business, operations and results in this Annual Report include RMP's business, operations and results. We record the non-controlling interest of the limited partners of RMP in our consolidated financial statements.

Our midstream assets consist of gathering systems and associated compression infrastructure in Washington and Greene Counties, Pennsylvania (owned by RMP), and gathering systems and associated compression infrastructure in Belmont County, Ohio, and fresh water distribution systems in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio. The following table provides information regarding our gathering and compression assets for the periods presented.

	Three Months Ended December 31, 2014	As of December 31, 2014		
	Average Daily Throughput (MDth/d)	Pipeline (miles)	Capacity (MDth/d)	Compression Capacity (HP)
RMP:				
Washington County System	351	71	2,772	7,320
Greene County System	166	10	420	—
Rice Energy:				
Belmont County System	74	21	525	—
Total	591	102	3,717	7,320

During 2014, we continued the build-out of our Pennsylvania gathering systems and initiated the build-out of our Ohio gathering system. In April 2014, we acquired a 28-mile, 6- to 16-inch gathering in eastern Washington County, Pennsylvania, and permits necessary to construct an 18-mile, 30-inch gathering pipeline connecting this system to the Texas Eastern Pipeline for approximately $111.4 million. The acquired system is supported by long-term contracts with acreage dedications covering approximately 21,000 acres from third parties. In November 2014, we completed construction of the 18-mile, 30-inch gathering pipeline.

We are also in the process of expanding three fresh water distribution systems that are expected to have direct access to approximately 25.9 MMGPD of fresh water from the Monongahela and Ohio Rivers and other regional sources. These systems service the well completion operations of our Exploration and Production segment.

In 2015, we plan to invest $390.0 million in our Midstream segment, which includes $180.0 million expected to be invested by RMP. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Segment Information

For additional information on operations by segment including, but not limited to, revenues from external customers, operating income and total assets, see Note 8 in the notes to consolidated financial statements under Item 8 of this Annual Report.

Markets and Customers

Exploration and Production Segment

Our Exploration and Production segment sells produced natural gas principally to natural gas marketers. Natural gas is a commodity and therefore we receive market-based pricing. The market price for natural gas can be volatile as demonstrated by significant declines in late 2014 and early 2015. In addition, the market price for natural gas in the Appalachian Basin experienced a decline relative to the price at Henry Hub, which is the location for pricing NYMEX and natural gas futures, in the second half of 2013 and 2014 as a result of the increased supply of natural gas in the Northeast region. While additional takeaway capacity has been and continues to be added to alleviate this supply/demand imbalance, the cost of new firm transportation projects has risen significantly in recent years. Changes in the market price for natural gas, including basis, impact our revenues, earnings and liquidity. We are unable to predict potential future movements in the market price for natural gas, including Appalachian basis differentials, and thus cannot predict the ultimate impact of prices on our operations; however, we monitor the market for natural gas and adjust strategy and operations as deemed to be appropriate. In order to protect cash flow from undue exposure to the risk of changing commodity prices, we hedge a portion of our forecasted natural gas production, most of which is hedged at NYMEX natural gas prices.

Our hedging strategy and information regarding our derivative instruments is set forth in "Commodity Hedging Activities" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations", Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," and in Note 4 to the consolidated financial statements in Item 8 of this Annual Report.

For the year ended December 31, 2014, sales to Sequent Energy Management, LP ("Sequent") represented 79% of our total sales. Although a substantial portion of production is purchased by this major customer, we do not believe the loss of this customer would have a material adverse effect on our business, as other customers or markets would be accessible to us. However, if we lose this customer, there is no guarantee that we will be able to enter into an agreement with a new customer which is as favorable as our current agreements.

Midstream Segment

Our Midstream segment derives gathering and compression revenues from charges to customers for use of its gathering systems and compression assets in Pennsylvania and Ohio. The gathering systems volumes are transported to six major interstate pipelines: Dominion Transmission, EQT Midstream, Columbia Gas Transmission, Texas Eastern Transmission, Natural Fuel Gas Supply and Dominion East Ohio.

Gathering system throughput volumes for 2014 totaled 402 MDth/d, of which approximately 90% related to gathering for our Exploration and Production segment and 10% related to third-party volumes. Prior to December 22, 2014, our Midstream segment did not charge fees for gathering and compression services provided to our Exploration and Production segment. As such, for 2014, our Exploration and Production segment accounted for only 24% of our natural gas gathering and compression revenues. Three third-party customers represented 60% and 96% of our Midstream segment gathering and compression revenues, respectively, for 2014.

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.

Seasonal anomalies of the nature described above can increase demand for midstream services during the summer and winter months and decrease demand for such services during the spring and fall months.

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.

Our Midstream segment faces competition in attracting third-party volumes to our gathering and compression systems. In addition, these third parties may develop their own gathering and compression systems in lieu of employing our assets. Our ability to attract such third-party volumes to our gathering and compression systems depends on our ability to evaluate and select suitable projects and to consummate transactions in a highly competitive environment. 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. 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 attracting third-party volumes to our gathering and compression systems, attracting and retaining quality personnel, and raising additional capital, which could have a material adverse effect on our Midstream segment.

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, 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 Federal Energy Regulatory Commission ("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 two 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.

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 Energy Policy Act of 2005, or EPAct 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 EPAct 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 EPAct 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 EPAct 2005. The rules make it unlawful: (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 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.

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.

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 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 Pipeline Safety and Maintenance

The Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), and Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), govern the design, installation, testing, construction, operation, replacement and management of natural gas, crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the DOT has promulgated regulations governing, among other things, pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. We believe that our pipeline operations are in substantial compliance with applicable requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, measures to ensure future compliance could result in increased costs.

These pipeline safety laws were amended on January 3, 2012, when President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (“2011 Pipeline Safety Act”), which requires increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of PHMSA guidance with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any of which could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. However, we do not expect that any such costs would be material to our financial condition or results of operations. We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking and sought public comment on a number of proposed changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 report to Congress from the U.S. Government Accountability Office (“GAO”), the GAO acknowledged PHMSA’s continued assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. We cannot predict what future action the DOT will take, but we do not believe that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas gatherers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

General

Our operations are subject to numerous federal, regional, state, local, and other laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), the Clean Water Act (“CWA”) and the Clean Air Act (“CAA”). These laws and regulations govern environmental cleanup standards, require permits for air emissions, water discharges, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, EPA’s 2014 – 2016 National Enforcement Initiatives include “Assuring Energy Extraction Activities Comply with Environmental Laws.” According to the EPA’s website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." The EPA has emphasized that this initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of our operations, and we cannot be sure that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

Hazardous Substances and Wastes

CERCLA, also known as the "Superfund law," imposes cleanup obligations, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be potentially responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA and any state analogs, such as Pennsylvania's Hazardous Sites Cleanup Act, may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file corresponding common law claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While petroleum and crude oil fractions are not considered hazardous substances under CERCLA and its analog because of the so-called "petroleum exclusion," adulterated petroleum products containing other hazardous substances have been treated as hazardous substances in the past.

The Resource Conservation and Recovery Act ("RCRA") regulates the generation and disposal of wastes. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." Instead, these wastes are regulated under RCRA's less stringent non hazardous solid waste provisions, state laws or other federal laws. However, legislation has been proposed from time to time that could reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, some ordinary industrial wastes which we generate, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous wastes.

In addition, current and future regulations governing the handling and disposal of Naturally Occurring Radioactive Materials ("NORM") may affect our operations. For example, the Pennsylvania Department of Environmental Protection has asked operators to identify technologically enhanced NORM ("TENORM") in their processes, such as hydraulic fracturing sand. Local landfills only accept such waste when it meets their TENORM permit standards. As a result, we may have to locate out-of-state landfills to accept TENORM waste from time to time, potentially increasing our disposal costs.

Some of our leases may have had prior owners who commenced exploration and production of natural gas and oil operations on these sites. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties may have been operated by third parties whose treatment and disposal or release of wastes were not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA, and/or analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Waste Discharges

The CWA and its state analog impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Federal spill prevention, control and countermeasure requirements require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. We believe that we maintain all required permits and/or authorizations necessary to conduct our operations, and we further believe we are in substantial compliance with the terms thereof. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Air Emissions

The CAA and state analogs and regulations restrict the emission of air pollutants from many sources, including oil and gas facilities. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs to remain in compliance. Over time more stringent regulations governing emissions of toxic air pollutants and greenhouse gases (GHGs) have been developed by the EPA and may increase the costs of compliance for some facilities. In 2012, the EPA issued federal regulations affecting our operations under the New Source Performance Standards provisions (new Subpart OOOO) and expanded regulations under national emission standards for hazardous air pollutants. On December 19, 2014, the EPA finalized amendments and clarifications to the NSPS rules, including, for example, updates and clarifications to requirements related to well completion, storage tanks, and leak detection. In addition, the Obama Administration is expected to release a series of new regulations affecting the oil and gas industry in 2015, including regulations limiting methane emissions from certain new and modified oil and gas facilities. 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.

Oil Pollution Act

The Oil Pollution Act of 1990 (“OPA”) and regulations thereunder impose a variety of requirements on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A “responsible party” includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (“NEPA”). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Endangered Species Act and Migratory Bird Treaty Act

The Endangered Species Act (“ESA”) and state analogs restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds we believe that we are in substantial compliance with such law. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Worker Safety

The Occupational Safety and Health Act ("OSHA") and any analogous state law regulate the protection of the safety and health of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Safe Drinking Water Act

The Safe Drinking Water Act ("SDWA") and comparable state provisions restrict the disposal of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state's environmental authority. These regulations, and any amendments to these regulations, may increase the costs of compliance for some facilities. Furthermore, in response to alleged seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, some agencies have imposed moratoria on the use of such injection wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase.

Employees

As of December 31, 2014, we had 290 full-time employees. 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 utilize the services of independent contractors to perform various field and other services.

Available Information

Our website is available at http://www.riceenergy.com. Information contained on or connected to our website is not incorporated by reference into this Annual Report and should not be considered part of this report or any other filing we make with the U.S. Securities and Exchange Commission ("SEC"). We make available, free of charge, on our website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after filing such reports with the SEC. Other information such as presentations, our Corporate Governance Guidelines, the charters of the Audit Committee, the Compensation Committee and the Nominating and Governance Committee, and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 400 Woodcliff Drive, Canonsburg, Pennsylvania 15317. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the Chief Executive Officer and Chief Financial Officer.
The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Rice Energy, that file electronically with the SEC. The public can obtain any document we file with the SEC at http://www.sec.gov.

Item 1A. Risk Factors

Investing in our common stock involves risks. You should carefully consider the information in this Annual Report, 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, operating results profitability, access to capital, future rate of growth and carrying value of our properties. 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. For example, the Henry Hub spot market price had declined from a high of $7.94 per MMBtu on March 5, 2014 to a low of $2.75 per MMBtu on December 25, 2014. Natural gas prices have remained depressed thus far in 2015, and the commodities 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 affecting the global supply of 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 and expectations about future commodity prices;
- the proximity, capacity, cost and availability of gathering and transportation facilities, and other factors that result in differentials to benchmark prices;
- localized and global supply and demand fundamentals and transportation availability;
- the actions of the Organization of the Petroleum Exporting Countries;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- the cost of exploring for, developing, producing and transporting reserves;
- speculative trading in natural gas and crude oil derivative contracts;
- risks associated with operating drilling rigs;
- increased end-user conservation or conversion of alternative fuels;
- the price and availability of competitors' supplies of natural gas and oil and alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Furthermore, the worldwide financial and credit crisis in recent years 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 economic environment reduced worldwide demand for energy and resulted in lower natural gas, NGL and oil prices.

In addition, substantially all of our natural gas production is sold to purchasers under contracts with market-based prices. The actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of location differentials. Location differentials to NYMEX Henry Hub prices, also known as basis differentials, result from variances in regional natural gas prices compared to NYMEX Henry Hub prices as a result of regional supply and demand factors. Historically, we have entered into long-term firm transportation arrangements pursuant to which our production is shipped to markets that we expect to be less impacted by basis differentials. In recent years, the cost of new firm transportation projects has risen significantly. There can be no assurance that the net impact of entering into such arrangements, after giving effect to their costs, will result in more favorable sales prices for our production in the future than local pricing. As such, our net sales prices may be materially less than NYMEX Henry Hub prices as a result of basis differentials and/or firm transportation costs.

Lower commodity prices and negative increases in our differentials 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 or our negative differentials further increase, a significant portion of our 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 or an increase in our negative differentials may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our 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 development and acquisition of natural gas reserves. In 2015, we plan to invest $1,070.0 million in our operations,

including $340.0 million for drilling and completion in the Marcellus Shale, $220.0 million for drilling and completion in the Utica Shale, $120.0 million for leasehold acquisitions and $390.0 million for midstream infrastructure development, including $180.0 million expected to be invested by RMP. Our capital budget excludes acquisitions, other than leasehold acquisitions. We expect to fund our 2015 capital expenditures with existing cash, cash generated by operations and borrowings under our revolving credit facilities. If we do not have sufficient borrowing availability under our revolving credit facilities, including our $550.0 million Senior Secured Revolving Credit Facility ("Senior Secured Revolving Credit Facility") due to the current commodity price environment or otherwise, we may seek alternate debt financing or reduce our capital expenditures. In addition, a portion of our 2015 capital budget is projected to be financed with cash flows from operations derived from wells drilled on drilling locations not associated with proved reserves in our reserve report. The failure to achieve projected production and cash flows from operations from such wells could result in a reduction to our 2015 capital budget. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in natural gas 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 revolving credit facilities; 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;
- our access to, and the cost of accessing, end markets for our production;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- our ability to borrow under our revolving credit facilities.

If our revenues or the borrowing base under our $550.0 million Senior Secured Revolving 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 planned capital budget or 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 revolving credit facilities 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 result in a total loss of investment or otherwise 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 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 or that we will not recover all or any portion of our investment in such wells or that various characteristics of the well will cause us to plug or abandon the well prior to producing in commercially viable quantities.
Our decisions to purchase, explore or develop prospects or properties will depend in 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 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 including limitations resulting from wastewater disposal, discharge of greenhouse gases, and limitations on hydraulic fracturing;
- 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, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as blizzards 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.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

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, with a particular concentration in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio. As of December 31, 2014 and 2013, all of our total estimated proved reserves were attributable to properties located in these areas. 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 these areas caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other weather related conditions or interruption of the processing or transportation of oil, natural gas or NGLs and changes in regional and local political regimes and regulations. Such conditions could have a material adverse effect on our financial condition and results of operations.

In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations. For example, third parties may engage in subsurface mining operations near or under our properties, which could cause subsidence or other damage to our properties, adversely impact our drilling or adversely impact our midstream activities or those on which we rely. In such event, our operations may be impaired or interrupted, and we may not be able to recover the costs incurred as a result of temporary shut-ins, the plugging and abandonment of any of our wells or the repair of our midstream facilities. Furthermore, the existence of mining operations near our properties could require coordination to avoid adverse impacts as a result of drilling and mining in close proximity. In connection with our aquisition of Alpha Holdings' 50% interest in our Marcellus joint venture on January 29, 2014, we agreed to continue to acknowledge the dominance of mining by Alpha Natural Resources, Inc. ("Alpha") within the area of mutual interest of our Marcellus joint venture. As such, in addition to coordinating with Alpha on, and in certain circumstances obtaining the prior approval of Alpha for, future drilling operations, we may also be required to take steps to assure the dominance of the mining operations of Alpha, including the plugging and abandonment of wells at the direction of Alpha upon two years notice. These restrictions on our operations, and any similar restrictions, can cause delays or interruptions or can prevent us from executing our business strategy, which could have a material adverse effect on our financial condition and results of operations.

Due to the concentrated nature of our portfolio of natural gas properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

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

We completed our first horizontal well in the Marcellus Shale in October 2010 and in the Utica Shale in June 2014. 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 more developed and have a longer history of established production. 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. Additionally, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. We cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

During the term of the Utica Development Agreements, we will rely on Gulfport for the success of our project in the Southern Contract Area in Belmont County, Ohio, and we may not be able to maximize the value of our properties in the Southern Contract Area as we deem best because we are not in full control of this project.

During the term of the Utica Development Agreements, the success of our operation in the Southern Contract Area in Belmont County, Ohio, will depend in part on the ability of Gulfport to effectively exploit the acreage it operates under the Development Agreement. Please read “Item 1. Business—Exploration and Production Business Segment—Development Agreement and Area of Mutual Interest Agreement.” Pursuant to the Development Agreement, we have designated Gulfport as the operator of our existing and future acreage in the Southern Contract Area. A failure or inability of Gulfport to adequately exploit the acreage it operates would have a significant impact on our results of operations. In addition, other than limitations set forth in the terms of the Development Agreement, we do not control the amount of capital that Gulfport may require for development of properties in the Southern Contract Area. Accordingly, we may be required to allocate capital to development of the Southern Contract Area at times when we otherwise would allocate capital to the Northern Contract Area, our Marcellus Shale acreage or elsewhere or otherwise be forced to terminate the Utica Development Agreements. Under any of these circumstances, our prospects for realization of the potential value of the oil, natural gas and NGL reserves associated with the Southern Contract Area could be adversely affected. Our lack of control may limit our ability to develop our properties in the manner we believe to be in our best interest.

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

The Appalachian Basin natural gas business environment has recently experienced periods in which production has surpassed local takeaway capacity, resulting in substantial discounts in the price received by producers such as us. Although additional Appalachian Basin takeaway capacity has been added in recent years, the existing and expected capacity may not be sufficient to keep pace with the increased production caused by accelerated drilling in the area in the short term. Furthermore, the costs associated with securing long-term firm transportation capacity has risen significantly on newer projects. There can be no assurance that the net impact of entering into such arrangements, after giving effect to their costs, will result in more favorable sales prices for our production in the future than local pricing. If we are unable to secure additional gathering and compression capacity and long-term firm takeaway capacity on major pipelines that are in existence or 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 are required to pay fees to our service providers based on minimum volumes regardless of actual volume throughput.

We have various gas transportation service agreements in place, each with minimum volume delivery commitments. As of March 1, 2015, our average annual contractual firm transportation and firm sales obligations for 2015, 2016 and 2017 were approximately 813,000 MMBtu/d, 918,000 MMBtu/d and 1,011,000 MMBtu/d, respectively. While we believe that our future natural gas volumes will be sufficient to satisfy the minimum requirements under our gas transportation services agreements based on our current production and our exploration and development plan, we can provide no such assurances that such volumes will be sufficient. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput, which could be significant. 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 revolving credit facility and the indenture (the “Indenture”) governing the $900.0 million aggregate principal amount of 6.25% senior notes due 2022 (the “Senior Notes”) we issued in a private placement on April 25, 2014 (the “Senior Notes Offering”) contain 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 or interest rates;
- incur liens;
- engage in certain other transactions without the prior consent of the lenders; and
- pay dividends.

In addition, our revolving credit facility and the Indenture require us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. On certain occasions in the past we have not met these financial covenants. These restrictions may 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 our revolving credit facility and under the Indenture impose on us.

Any significant reduction in our borrowing base under our Senior Secured Revolving Credit Facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our Senior Secured Revolving 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 the 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. As of December 31, 2014, we did not have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under our revolving credit facility. As of October 2014, the borrowing base under our Senior Secured Revolving Credit Facility was $550.0 million. The commodity prices used by our lenders in our most recent borrowing base determination were not reflective of the substantially lower commodity prices realized in December 2014 and January 2015. Our next scheduled borrowing base redetermination is expected to occur in April 2015.

A breach of any covenant in our revolving credit facility would result in a default under the facility after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the relevant facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements that include cross default provisions. 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.

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 December 31, 2014, we had entered into NYMEX hedging contracts through December 31, 2017 covering a total of approximately 202 Bcf of our projected natural gas production at a weighted average price of $4.09 per MMBtu. We have also

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entered into Appalachian hedging contracts through December 31, 2016 covering a total of approximately 45 Bcf of our projected natural gas production at a weighted average price of $2.72 per MMBtu. 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 reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating natural gas 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 the estimated quantities and present value of our reserves.

In order to prepare reserve 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. As a substantial portion of our reserve estimates are made without the benefit of a lengthy production history, any significant variance from the above assumption could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust 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 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. Please see "—The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves."

Reserve estimates for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. Less production history may contribute to less accurate estimates of reserves, future production rates and the timing of development expenditures. A substantial number of our producing wells have been operational for less than two years and estimated reserves vary substantially from well to well. Furthermore, the lack of operational history for horizontal wells in the Utica Shale may also contribute to the inaccuracy of future estimates of reserves and could result in our failing to achieve expected results in the play. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our drilling 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 drilling 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, the availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, gathering system and pipeline transportation costs, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling 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 drilling 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. Further, certain of the horizontal wells we intend to drill in the future may require unitization with adjacent leaseholds controlled by third parties. If these third parties are unwilling to unitize such leaseholds with ours, this may limit the total locations we can drill. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2014, we had 1,233 net drilling locations. As a result of the limitations described above, we may be unable to drill many of these 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, may not increase 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 drilling locations, see "Item 2. Properties—Exploration and Production Segment—Reserve Data—Determination of Drilling Locations."

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on our oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2014, we had leases representing 2,905 undeveloped acres scheduled to expire in 2015, 5,694 undeveloped acres scheduled to expire in 2016, 31,988 undeveloped acres scheduled to expire in 2017, 35,498 undeveloped acres scheduled to expire in 2018 and 22,850 undeveloped acres set to expire in 2019 and thereafter. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Moreover, many of our leases require lessor consent to unitize, which may make it more difficult to hold our leases by production. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. Our reserves and future production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage and the loss of any leases could materially and adversely affect our ability to so develop such acreage.

The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2014, 2013 and 2012, we based the discounted future net cash flows from our proved reserves on the 12-month first-day-of-the-month oil and natural gas average prices without giving effect to derivative transactions. Accordingly, the natural gas price used in our reserve report as of December 31, 2014 was $4.52 per Mcfe, which is not reflective of the substantially lower prices realized in December 2014 and January 2015. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. As a corporation, we are treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent on our future taxable income. Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report which could have a material effect on the value of our reserves.

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

Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due to the long history of land ownership in the area, resulting in extensive and complex chains of title. In the course of acquiring the rights to develop oil and natural gas, it is standard procedure for us and the lessor to execute a lease agreement with payment subject to title verification. In most cases, we incur the expense of retaining lawyers to verify the rightful owners of the oil and gas interests prior to payment of such lease bonus to the lessor. There is no certainty, however, that a lessor has valid title to its lease's oil and gas interests. In those cases, such leases are generally voided and payment is not remitted to the lessor. As such, title failures may result in fewer net acres to us. Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Accordingly, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

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

As of December 31, 2014, approximately 51% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 662.4 Bcfe of estimated proved undeveloped reserves will require an estimated $585.3 million of development capital over the next five years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we 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.

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 development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future 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, 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.

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 December 31, 2014, we had entered into NYMEX hedging contracts through December 31, 2017 covering a total of approximately 202 Bcf of our projected natural gas production at a weighted average price of $4.09 per MMBtu. We have also entered into Appalachian hedging contracts through December 31, 2016 covering a total of approximately 45 Bcf of our projected natural gas production at a weighted average price of $2.72 per MMBtu. 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.

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. As of December 31, 2014, the estimated fair value of our commodity derivative contracts was approximately $196.2 million. Any default by the counterparties to these derivative contracts when they become due would have a material adverse effect on our financial condition and results of operations.

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.

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 ($125.3 million at December 31, 2014) and the sale of our natural gas production to natural gas marketing companies ($72.2 million in receivables as of December 31, 2014), including one natural gas marketing company which represented $30.7 million in receivables at December 31, 2014. 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 one natural gas marketing company. The largest purchaser of our natural gas during the year ended December 31, 2014 represented approximately 79% of our total sales. 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 are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities that could exceed current expectations.

Substantial costs, liabilities, delays and other significant issues could arise from environmental laws and regulations inherent in drilling and well completion, gathering, transportation, and storage, and we may incur substantial costs and liabilities in the performance of these types of operations. Our operations are subject to extensive federal, regional, state and local laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

- CAA, and analogous state law, which impose obligations related to air emissions;
- Clean Water Act ("CWA"), and analogous state law, which regulate discharge of wastewaters and storm water from some of our facilities into state and federal waters, including wetlands;
- CERCLA, and analogous state law, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;
- RCRA, and analogous state law, which impose requirements for the handling and discharge of any solid and hazardous waste from our facilities;
- NEPA, which requires federal agencies to study likely environmental impacts of a proposed federal action before it is approved, such as drilling on federal lands;
- SDWA, and analogous state law, which restrict the disposal, treatment or release of water produced or used during oil and gas development;
- ESA, and analogous state law, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species; and
- OPA of 1990, which requires oil storage facilities and vessels to submit to the federal government plans detailing how they will respond to large discharges, requires updates to technology and equipment, regulates above ground storage tanks and sets forth liability for spills by responsible parties.

Various governmental authorities, including, for example, the U.S. Environmental Protection Agency (the "EPA"), the U.S. Department of the Interior, the Bureau of Indian Affairs and analogous state agencies and tribal governments, have the

power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and/or criminal fines and penalties and liability for non-compliance, the imposition of remedial obligations, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions or declaratory relief limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to the handling of our products as they are gathered, transported, processed and stored, air emissions related to our operations, historical industry operations, and water and waste disposal practices. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including CERCLA, RCRA and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of natural gas, oil and wastes on, under, or from our properties and facilities. Private parties may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate may be located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

The EPA's National Enforcement Initiatives for 2014 to 2016, includes "Assuring Energy Extraction Sector Compliance with Environmental Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, and any new capital costs may be incurred to comply with such changes. In addition, new environmental laws and regulations might adversely affect our products and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability. Further, new environmental laws and regulations might adversely affect our customers, which in turn could affect our profitability.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

Pursuant to the authority under the NGPSA and HLPSA, as amended by the Pipeline Safety Improvement Act, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and the 2011 Pipeline Safety Act, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of pipeline integrity testing, but the results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the safe and reliable operation of our pipelines.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA or states that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking and sought public comment on a number of proposed changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 GAO report to Congress, the GAO acknowledged PHMSA’s assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

Changes in laws or government regulations regarding hydraulic fracturing could increase our costs of doing business, limit the areas in which we can operate and reduce our oil and natural gas production, which could adversely impact our business.

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. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. The SDWA regulates the underground injection of substances through the Underground Injection Control (“UIC”) program and exempts hydraulic fracturing from the definition of “underground injection”. Congress has in recent legislative sessions considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as require disclosure of the chemical constituents of the fluids used in the fracturing process. The U.S. Congress may consider similar SDWA legislation in the future.

In addition, EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published final permitting guidance in February 2014 addressing the performance of such activities using diesel fuels in those states where EPA is the permitting authority. Also, in May 2014, the EPA issued an advanced notice of proposed rules under the Toxic Substances Control Act that would require companies to disclose information regarding the chemicals used in hydraulic fracturing. In addition, the U.S. Department of the Interior published a revised proposed rule on May 16, 2013, that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. Further, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, and a draft final report with conclusions about the potential impacts of hydraulic fracturing on drinking water resources is expected to be available for public comment and peer review sometime in the first half of 2015. 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 in 2015. And other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Along with several other states, Pennsylvania (where we conduct a majority of our operations) has adopted laws and proposed regulations that require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. The chemical ingredient information is generally available to the public via online databases, and this may bring more public scrutiny to hydraulic fracturing operations. In addition, local governments may also adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. Although the Pennsylvania legislature passed legislation to make regulation of drilling uniform throughout the state, the Pennsylvania Supreme Court in Robinson Township v. Commonwealth of Pennsylvania struck down portions of that legislation. Following this decision, local governments in Pennsylvania may increasingly adopt ordinances relating to drilling and hydraulic fracturing activities, especially within residential areas. 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.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly for our customers to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities by our customers and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Restrictions on the ability to obtain water may impact our operations.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations.

Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The CWA imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Specific to Pennsylvania, sending wastewater to POTWs requires certain levels of pretreatment that may effectively prohibit such disposal as a disposal option and our continued ability to use injection wells as a disposal option not only will depend on federal or state regulations but also on whether available injection wells have sufficient storage capacities. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

We are subject to risks associated with climate change.

There is a growing belief that emissions of GHGs may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks. In addition, legislative and regulatory responses related to GHGs and climate change creates the potential for financial risk. The U.S. Congress has previously considered legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions. For example, the Obama administration recently announced its Climate Action Plan, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and gas sector.

On September 22, 2009, the EPA finalized a GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions beginning January 1, 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent (CO_2e) emissions per year and to most upstream suppliers of fossil fuels, as well as manufacturers of vehicles and engines. Subsequently, on November 8, 2010, the EPA issued GHG monitoring and reporting regulations that went into effect on December 30, 2010, specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of CO_2e per year. The rule requires reporting of GHG emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. We are required to report our GHG emissions to the EPA each year in March under this rule. Recently, the EPA finalized modifications to its GHG reporting rules that would require covered entities to report emissions on an individual GHG basis. In addition, the EPA has proposed a rule that would expand the agency's reporting requirements to cover completions and workovers from hydraulically fractured oil wells. These changes to EPA's reporting rules could result in increased compliance costs.

The recent actions of the EPA and the passage of any federal or state climate change laws or regulations could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

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.

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.

In accordance with what we believe to be customary industry practice, we maintain insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flows. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial condition. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are a large part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the “occurrence” to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows.

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.

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

Properties that we decide to drill that do not yield natural gas, NGLs or oil in commercially viable quantities will adversely affect our results of operations and financial condition. Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. If the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected. In addition, there is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas, NGLs 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, NGLs or oil will be present or, if present, whether natural gas, NGLs 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 canceled 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. However, 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.

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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 facilities impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facilities also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

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

The successful acquisition of natural gas and oil properties requires an assessment of several factors, including:

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