Rice Energy Inc.
Form S-4
December 03, 2014
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As filed with the Securities and Exchange Commission on December 2, 2014

Registration No. 333-

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-4

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

RICE ENERGY INC.

(AND CERTAIN SUBSIDIARIES OF RICE ENERGY INC. IDENTIFIED IN

FOOTNOTE (*) BELOW)

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1311**	**46-3785773**
(State or Other Jurisdiction of Incorporation or Organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification Number)**

400 Woodcliff Drive

Canonsburg, Pennsylvania 15317

(724) 746-6720

(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)

Daniel J. Rice IV

Chief Executive Officer

Rice Energy Inc.

400 Woodcliff Drive

Canonsburg, Pennsylvania 15317

(724) 746-6720

(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent For Service)

Copies to:

Douglas E. McWilliams

Alan Beck

Vinson & Elkins L.L.P.

1001 Fannin, Suite 2500

Houston, Texas 77002

(713) 758-2222

Approximate date of commencement of proposed sale of the securities to the public:

As soon as practicable after the effective date of this Registration Statement.

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box. ¨

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

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

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

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

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction:

Exchange Act Rule 13e-4(i) (Cross-Border Issue Tender Offer) ¨

Exchange Act Rule 14d-1(d) (Cross-Border Third-Party Tender Offer) ¨

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to Be Registered	**Amount to be Registered**	**Amount of Registration Fee(1)**
6.25% Senior Notes due 2022	$900,000,000	$104,580
Guarantees of 6.25% Senior Notes due 2022(2)		None(3)

(1) Calculated pursuant to Rule 457(f)(2) under the Securities Act of 1933.
(2) Each subsidiary of Rice Energy Inc. that is listed on the Table of Additional Registrant Guarantors has guaranteed the notes being registered.

(3) Pursuant to Rule 457(n) of the Securities Act of 1933, no registration fee is required for the Guarantees.

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

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TABLE OF ADDITIONAL REGISTRANT GUARANTORS

*** The following are co-registrants that guarantee the debt securities:**

Exact Name of Registrant Guarantor(1)	State or Other Jurisdiction of Incorporation or Formation	IRS Employer Identification Number
Rice Marketing LLC	Delaware	47-2089524
Rice Energy Marketing LLC	Delaware	45-4877837
Rice Energy Appalachia, LLC	Delaware	61-1671607
Rice Drilling B LLC	Delaware	26-1953720
Rice Drilling C LLC	Pennsylvania	27-0970344
Rice Drilling D LLC	Delaware	90-0779528
Rice Poseidon Midstream LLC	Delaware	30-0787520
Rice Olympus Midstream LLC	Delaware	61-1715254
Blue Tiger Oilfield Services LLC	Delaware	61-1671607
Alpha Shale Holdings, LLC	Delaware	27-1785095
Alpha Shale Resources, LP	Delaware	27-1785246

(1) The address for each Registrant Guarantor is 400 Woodcliff Drive, Canonsburg, Pennsylvania 15317, and the telephone number for each Registrant Guarantor is (724) 746-6720. The Primary Industrial Classification Code for each Registrant Guarantor is 1311.

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

Subject to completion, dated December 2, 2014

PROSPECTUS

Rice Energy Inc.

Offer to Exchange

Up To $900,000,000 of

6.25% Senior Notes due 2022

That Have Not Been Registered Under

The Securities Act of 1933

For

Up To $900,000,000 of

6.25% Senior Notes due 2022

That Have Been Registered Under

The Securities Act of 1933

Terms of the New 6.25% Senior Notes due 2022 Offered in the Exchange Offer:

- The terms of the new notes are identical to the terms of the old notes that were issued on April 25, 2014, except that the new notes will be registered under the Securities Act of 1933 (the Securities Act) and will not contain restrictions on transfer, registration rights or provisions for additional interest.

Terms of the Exchange Offer:

We are offering to exchange up to $900,000,000 of our old notes for new notes with materially identical terms that have been registered under the Securities Act and are freely tradable.

We will exchange all old notes that you validly tender and do not validly withdraw before the exchange offer expires for an equal principal amount of new notes.

The exchange offer expires at 5:00 p.m., New York City time, on , 2014, unless extended.

Tenders of old notes may be withdrawn at any time prior to the expiration of the exchange offer, in accordance with the procedures set forth herein.

We believe that the exchange of new notes for old notes will not be a taxable event for U.S. federal income tax purposes.

Broker-dealers who receive new notes pursuant to the exchange offer acknowledge that they will deliver a prospectus in connection with any resale of such new notes.

Broker-dealers who acquired the old notes as a result of market-making or other trading activities may use the prospectus for the exchange offer, as supplemented or amended, in connection with resales of the new notes.

You should carefully consider the risk factors beginning on page 7 of this prospectus before participating in the exchange offer.

We are not asking you for a proxy and you are requested not to send us a proxy.

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

The date of this prospectus is , 2014.

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This prospectus is part of a registration statement we filed with the Securities and Exchange Commission. In making your investment decision, you should rely only on the information contained in this prospectus and in the accompanying letter of transmittal. We have not authorized anyone to provide you with any other information. We are not making an offer to sell these securities or soliciting an offer to buy these securities in any jurisdiction where an offer or solicitation is not authorized or in which the person making that offer or solicitation is not qualified to do so or to anyone whom it is unlawful to make an offer or solicitation. You should not assume that the information contained in this prospectus is accurate as of any date other than its respective date.

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This prospectus refers to important business and financial information about Rice Energy Inc. that is not included or delivered with this prospectus. Such information is available without charge to holders of old notes upon written or oral request made to the office of Rice Energy Inc., 400 Woodcliff Drive, Canonsburg, Pennsylvania 15317 (Telephone: (724) 746-6720). To obtain timely delivery of any requested information, holders of old notes must make any request no later than , 2015 which is five business days prior to the expiration of the exchange offer.

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Commonly Used Defined Terms

As used in this prospectus, 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 to Rice Energy Inc. and its consolidated subsidiaries, including Rice Drilling B LLC;

Rice Drilling B refers to Rice Drilling B LLC, our wholly-owned subsidiary;

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, which was dissolved in November 2014;

Rice Holdings refers to Rice Energy Holdings LLC;

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.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas, 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 prospectus that are not historical.

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

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously.

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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, and NGLs and oil that are ultimately recovered.

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

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

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

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PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully before making an investment decision, including the information under the headings Risk Factors, Cautionary Statement Regarding Forward-Looking Statements and Management s Discussion and Analysis of Financial Condition and Results of Operations and the historical consolidated and unaudited pro forma financial statements and the related notes thereto appearing elsewhere in this prospectus. The estimated proved reserve information for the properties of each of us and our Marcellus joint venture contained in this prospectus are based on reserve reports relating thereto prepared by the independent petroleum engineers of Netherland, Sewell & Associates, Inc. (NSAI). We refer to these reports collectively as our reserve reports. We have provided definitions for some of the oil and natural gas industry terms used in this prospectus in the Glossary of Natural Gas and Oil Terms in Appendix A to this prospectus.

In this prospectus we refer to the notes to be issued in the exchange offer as the new notes and the notes issued on April 25, 2014 as the old notes. We refer to the new notes and the old notes collectively as the notes.

Rice Energy Inc.

We are an independent natural gas and oil company engaged in the acquisition, exploration and development of natural gas and oil properties in the Appalachian Basin. We are focused on creating shareholder value by identifying and assembling a portfolio of low-risk assets with attractive economic profiles and leveraging our technical and managerial expertise to deliver industry-leading results. We strive to be an early entrant into the core of a shale play by identifying what we believe to be the core of the play and aggressively executing our acquisition strategy to establish a largely contiguous acreage position.

Our principal executive offices are located at 400 Woodcliff Drive, Canonsburg, Pennsylvania 15317, and our telephone number at our offices is (724) 746-6720.

Risk Factors

Investing in the notes involves substantial risks. You should carefully consider all the information contained in this prospectus prior to participating in the exchange offer. In particular, we urge you to consider carefully the factors set forth under Risk Factors beginning on page 7 of this prospectus.

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The Exchange Offer

On April 25, 2014 we completed the private offering of the old notes. We entered into a registration rights agreement with the initial purchasers in the private offering in which we agreed to deliver to you this prospectus and to use our reasonable best efforts to complete the exchange offer within 365 days after the date we first issued the old notes.

Exchange Offer	We are offering to exchange new notes for old notes.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on , 2014, unless we decide to extend it.
Condition to the Exchange Offer	The registration rights agreement does not require us to accept old notes for exchange if the exchange offer, or the making of any exchange by a holder of the old notes, would violate any applicable law or interpretation of the staff of the Securities and Exchange Commission. The exchange offer is not conditioned on a minimum aggregate principal amount of old notes being tendered.
Procedures for Tendering Old Notes	To participate in the exchange offer, you must follow the procedures established by The Depository Trust Company, which we call DTC, for tendering notes held in book-entry form. These procedures, which we call ATOP, require that (i) the exchange agent receive, prior to the expiration date of the exchange offer, a computer generated message known as an agent s message that is transmitted through DTC s automated tender offer program, and (ii) DTC confirms that: DTC has received your instructions to exchange your notes, and you agree to be bound by the terms of the letter of transmittal. For more information on tendering your old notes, please refer to the section in this prospectus entitled Exchange Offer Terms of the Exchange Offer, Procedures for Tendering, and Description of Notes Book-Entry, Delivery and Form.
Guaranteed Delivery Procedures	None.
Withdrawal of Tenders	

	You may withdraw your tender of old notes at any time prior to the expiration date. To withdraw, you must submit a notice of withdrawal to the exchange agent using ATOP procedures before 5:00 p.m., New York City time, on the expiration date of the exchange offer. Please refer to the section in this prospectus entitled Exchange Offer Withdrawal of Tenders.
Acceptance of Old Notes and Delivery of New Notes	If you fulfill all conditions required for proper acceptance of old notes, we will accept any and all old notes that you properly tender in the exchange offer on or before 5:00 p.m., New York City time, on the expiration date. We will return any old notes that we do not accept for exchange to you without expense promptly after the expiration date and acceptance of the old notes for exchange. Please refer to the section in this prospectus entitled Exchange Offer Terms of the Exchange Offer.

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Fees and Expenses	We will bear the expenses related to the exchange offer. Please refer to the section in this prospectus entitled Exchange Offer Fees and Expenses.
Use of Proceeds	The issuance of the new notes will not provide us with any new proceeds. We are making this exchange offer solely to satisfy our obligations under our registration rights agreement.
Consequences of Failure to Exchange Old Notes	If you do not exchange your old notes in this exchange offer, you will no longer be able to require us to register the old notes under the Securities Act except in limited circumstances provided under the registration rights agreement. In addition, you will not be able to resell, offer to resell or otherwise transfer the old notes unless we have registered the old notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act.
U.S. Federal Income Tax Considerations	The exchange of new notes for old notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please read Material United States Federal Income Tax Consequences.
Exchange Agent	We have appointed Wells Fargo Bank, National Association as exchange agent for the exchange offer. You should direct questions, requests for assistance, requests for additional copies of this prospectus or the letter of transmittal to the exchange agent addressed as follows:
	by registered or certified mail at Wells Fargo Bank, National Association, Corporate Trust Operations, MAC N9303-121, P.O. Box 1517, Minneapolis, MN 55480; or
	by Overnight Delivery or Regular Mail at Wells Fargo Bank, National Association, Corporate Trust Operations, MAC N9303-121, Sixth Street & Marquette Avenue, Minneapolis, MN 55479.
	Eligible institutions may make requests by facsimile at (877) 407-4679, Attn: Bondholder Communications, and may confirm facsimile delivery by telephone at (800) 344-5128.

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Terms of the New Notes

The new notes will be identical to the old notes except that the new notes are registered under the Securities Act and will not have restrictions on transfer, registration rights or provisions for additional interest. The new notes will evidence the same debt as the old notes, and the same indenture will govern the new notes and the old notes.

The following summary contains basic information about the new notes and is not intended to be complete. It does not contain all information that is important to you. For a more complete understanding of the new notes, please refer to the section of this document entitled Description of Notes.

Issuer	Rice Energy Inc.
Securities	$900,000,000 aggregate principal amount of 6.25% Senior Notes due 2022.
Maturity	May 1, 2022.
Interest	6.250% per year (calculated using a 360-day year).
Interest Payment Dates	May 1 and November 1 of each year, with the next interest payment being due May 1, 2015. Interest on each new note will accrue from the last interest payment date on which interest was paid on the old note tendered in exchange thereof, or, if no interest has been paid on the old note, from the date of the original issue of the old note.
Optional Redemption	At any time prior to May 1, 2017, we may, from time to time, redeem up to 35% of the aggregate principal amount of the notes in an amount of cash not greater than the net cash proceeds of certain equity offerings at the redemption price set forth under Description of Notes Optional Redemption, if at least 65% of the aggregate principal amount of the notes issued under the indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering.
	At any time prior to May 1, 2017, we may, on any one or more occasions, redeem all or a part of the notes at a redemption price equal to 100% of the principal amount of the notes redeemed, plus the make whole premium as of, and accrued and unpaid interest, if any, to the date of redemption. See Description of Notes Optional Redemption.

	On or after May 1, 2017 at the redemption prices set forth in this prospectus under the heading Description of Notes Optional Redemption.
Subsidiary Guarantees	The notes are guaranteed by all of our existing subsidiaries (other than one immaterial subsidiary) and may be guaranteed by certain future subsidiaries. All of our guarantor subsidiaries also guarantee our obligations under our revolving credit facility on a senior secured basis. In the future, the guarantees may be released or terminated under certain circumstances. See Description of Notes Brief

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	Description of the Notes and Subsidiary Guarantees The Subsidiary Guarantees and Description of Notes Certain Covenants Additional Subsidiary Guarantees.
	Each subsidiary guarantee will rank:
	equal in right of payment to all existing and future senior indebtedness of the guarantor subsidiary;
	effectively subordinate in right of payment to all existing and future secured indebtedness of the guarantor subsidiary, including its guarantee of indebtedness under our revolving credit facility, to the extent of the value of the collateral securing such indebtedness; and
	senior in right of payment to any future subordinated indebtedness of the guarantor subsidiary.
Ranking	The new notes:
	rank equally in right of payment to all of our existing and future senior indebtedness;
	are effectively subordinate in right of payment to all of our existing and future secured indebtedness, including indebtedness under our revolving credit facility, to the extent of the value of the collateral securing such indebtedness;
	are structurally subordinate in right of payment to all existing and future indebtedness and other liabilities, including trade payables, of any subsidiaries that do not guarantee the notes (other than indebtedness and other liabilities owed to us); and
	are senior in right of payment to all of our future subordinated indebtedness.
	As of September 30, 2014, we and our subsidiary guarantors had approximately $901.0 million of outstanding indebtedness, including no borrowings under our revolving credit facility, $66.8 million of

	outstanding letters of credit and we had approximately $318.2 million of borrowing capacity under our revolving credit facility.
Change of Control	If we experience certain kinds of changes of control followed by a rating decline, each holder of the notes may require us to repurchase all or a portion of its notes for cash at a price equal to 101% of the aggregate principal amount of such notes, plus any accrued and unpaid interest to the date of repurchase. See Description of Notes Repurchase at the Option of Holders Change of Control.
Certain Covenants	We will issue the new notes under the indenture dated as of April 25, 2014 with Wells Fargo Bank, National Association, as trustee. The indenture, among other things, limits our ability and the ability of our restricted subsidiaries (as defined under Description of Notes) to:
	incur or guarantee additional indebtedness or issue certain types of preferred stock;

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- pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness;
- transfer or sell assets;
- make investments;
- create certain liens;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates; and
- create unrestricted subsidiaries.

The covenants set forth in the indenture are subject to important exceptions and qualifications that are described under Description of Notes Certain Covenants. If the notes achieve an investment grade rating from each of Moody s Investors Service, Inc. and Standard & Poor s Ratings, many of these covenants will terminate.

Transfer Restrictions; Absence of a Public Market for the New Notes	The new notes generally will be freely transferable, but will also be new securities for which there will not initially be a market. There can be no assurance as to the development, maintenance or liquidity of any market for the new notes.
	We do not intend to apply for a listing of the new notes on any securities exchange or any automated dealer quotation system.
Risk Factors	Investing in the new notes involves risks. See Risk Factors beginning on page 7 for a discussion of certain factors you should consider in evaluating whether or not to tender your old notes.

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RISK FACTORS

This offering involves a high degree of risk. You should carefully consider and evaluate all of the information and data included in this prospectus before deciding to participate in the exchange offer. The risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also impair our business operations. If any of the following risks actually occur, our business, financial condition and results of operations could be materially and adversely affected and we may not be able to achieve our goals. We cannot assure you that any of the events discussed in the risk factors below will not occur. If these risks occur, the value of our securities could decline and you could lose some or all of your investment. The trading price of the new notes could decline, and you may lose all or part of your investment. The risks described below are not the only ones facing our company.

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 production heavily influence, and to the extent we produce oil and NGLs in the future, the prices we receive for oil and NGL production will 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. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions 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;

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;

the price and availability of competitors supplies of natural gas and oil and alternative fuels; and

domestic, local and foreign governmental regulation and taxes.

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

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. We may experience differentials to NYMEX Henry Hub prices in the future, which may be material.

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 2014, we plan to invest $1,230.0 million in our operations (excluding acquisitions), including $430.0 million for drilling and completion in the Marcellus Shale, $150.0 million for drilling and completion in the Utica Shale, $385.0 million for leasehold acquisitions and $265.0 million for midstream infrastructure development. Our capital budget excludes acquisitions, other than leasehold acquisitions. We expect to fund our 2014 capital expenditures with cash generated by operations, borrowings under our revolving credit facility, a portion of the net proceeds of our IPO, the proceeds from our offering of $900.0 million in aggregate principal amount of the notes completed on April 25, 2014 (our Senior Notes Offering) and the proceeds from our August 2014 public offering of 13,729,650 shares of our common stock (the August 2014 Equity Offering). A portion of our 2014 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 reports. The failure to achieve projected production and cash flows from operations from such wells could result in a reduction to our 2014 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 facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

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

- our proved reserves;

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- 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 facility.

If our revenues or the borrowing base under our 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 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 facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling, including or as a result of the application of these techniques, include, but are not limited to, the following:

- effectively controlling the level of pressure flowing from particular wells;
- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells, including or as a result of the application of these techniques, include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

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 Marcellus Shale and Upper Devonian Shale formations in Washington and Greene Counties, Pennsylvania. As of December 31, 2013 and 2012, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs 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 Marcellus Shale and Utica Shale 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 our acquisition of Alpha Holdings 50% interest in our Marcellus joint venture on January 29, 2014 (the Marcellus JV Buy-In), we agreed to continue to acknowledge the dominance of mining by Alpha Natural Resources, Inc. within the area of mutual interest of our Marcellus joint venture. As such, in addition to coordinating with Alpha Holdings on, and in certain circumstances obtaining the prior approval of Alpha Holdings for, future drilling operations, we may also be required to take steps to assure the dominance of the mining operations of Alpha Natural Resources, Inc., including the plugging and abandonment of wells at the direction of Alpha Holdings 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 completed our first horizontal well 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. For example, as a result of unexpected levels of pressure, in December 2013 we plugged and abandoned the first well we spud in the Utica Shale. We have since drilled and completed our second well in the Utica Shale and obtained an initial production test from this well in the second quarter of 2014. 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 Business Our Properties Utica Shale 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.

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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 was added in 2013 and 2012, the existing and expected capacity may not be sufficient to keep pace with the increased production caused by accelerated drilling in the area. We expect that a significant portion of our production from the Utica Shale will be transported on pipelines that experience a differential to NYMEX Henry Hub prices. 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 June 30, 2014, our average annual contractual firm transportation and firm sales obligations for 2014 (July through December), 2015 and 2016 were approximately 450,000 MMBtu/d, 810,000 MMBtu/d, and 920,000 MMBtu/d, respectively, which are in excess of our pro forma average daily gross operated production of approximately 380,000 MMBtu/d for June 2014. 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 contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness), including restrictive covenants that may limit our ability to, among other things:

- sell assets;
- make loans to others;
- make investments;
- enter into mergers;

- make certain payments;
- hedge future production or interest rates;
- incur liens;
- engage in certain other transactions without the prior consent of the lenders; and
- pay dividends.

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

Any significant reduction in our borrowing base under our revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our 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 our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid, or we must pledge other natural gas properties as additional collateral after applicable grace periods. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under our revolving credit facility. The borrowing base under our revolving credit facility is currently $550.0. 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 such facility after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under such 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.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management.

We completed our IPO in January 2014. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. We also incur costs associated with our public company reporting requirements and with corporate governance requirements, including requirements under the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority. These rules and regulations will increase our legal and financial compliance costs and make some activities more time consuming and costly, and we expect that these costs may increase further after we are no longer an emerging growth company. These rules and regulations make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

However, for as long as we remain an emerging growth company as defined in the JOBS Act, we intend to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved.

We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues in a fiscal year, become a large accelerated filer, or issue more than $1.0 billion of non-convertible debt over a three-year period.

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After we are no longer an emerging growth company, we expect to incur significant additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not emerging growth companies.

In connection with past audits and reviews of our financial statements and those of our Marcellus joint venture, our independent registered public accounting firms identified and reported adjustments to management. Certain of such adjustments were deemed to be the result of internal control deficiencies that constituted a material weakness in internal controls over financial reporting. If we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.

Prior to the completion of our IPO, we were a private company with limited accounting personnel to adequately execute our accounting processes and other supervisory resources with which to address our internal control over financial reporting. In addition, our Marcellus joint venture previously relied on our accounting personnel for its accounting processes. Historically, we and our Marcellus joint venture had not maintained effective internal control environments in that the design and execution of such controls had not consistently resulted in effective review and supervision by individuals with financial reporting oversight roles. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare the financial statements of us and our Marcellus joint venture. We concluded that these control deficiencies constituted material weaknesses in our control environment for the year ended December 31, 2012. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. The control deficiencies described above, at varying degrees of severity, contributed to the material weaknesses in the control environment as further described in Management s Discussion and Analysis of Financial Condition and Results of Operations Material Weaknesses in Internal Control over Financial Reporting.

To address these control deficiencies, we have hired additional accounting and financial reporting staff, implemented additional analysis and reconciliation procedures and increased the levels of review and approval. Additionally, we have begun taking steps to comprehensively document and analyze our system of internal control over financial reporting in preparation for our first management report on internal control over financial reporting in connection with our annual report for the year ending December 31, 2014. Due to the recent implementation of these changes to our control environment, management continues to evaluate the design and effectiveness of these control changes in connection with its ongoing evaluation, review, formalization and testing of our internal control environment over the remainder of 2014. We have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures as of September 30, 2014. Based upon the status of our review, we and our independent auditors have concluded that the material weakness previously identified had not been remediated as of September 30, 2014. During the course of the review, we may identify additional control deficiencies, which could give rise to significant deficiencies and other material weaknesses in addition to the material weakness previously identified. Our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future.

For the year ended December 31, 2013, we were not required to comply with the SEC s rules implementing Section 404 of the Sarbanes Oxley Act internal control over financial reporting. As a public company, we are required to comply with the SEC s rules implementing Section 302 of the Sarbanes Oxley Act, which require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Though we will be required to disclose material changes made to our internal controls and procedures on a quarterly basis, we will not be required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 until the year following our first annual report required to be filed with the SEC. To comply with the requirements of being a publicly traded company, we have upgraded our systems, including information technology, implemented additional financial and management controls, reporting systems and procedures and hired additional accounting and finance staff. Furthermore, while we generally must comply with Section 404 of the Sarbanes Oxley Act of 2002 for our fiscal year ending December 31, 2014, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an emerging growth company within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our annual report for the fiscal year ending December 31, 2019. We can provide no assurance that our independent registered public accounting firm will be satisfied with the level at which our controls are documented, designed, or operating at the time it issues its report.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our shares of common stock. company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our shares of common stock.

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, 2013, on a pro forma basis, we had entered into hedging contracts through December 31, 2017 covering a total of approximately 186 Bcf of our projected natural gas production at a weighted average price of $4.09 per MMBtu. For the period from January 1, 2014 until December 31, 2014, we have hedged approximately 62.9 Bcf of our projected natural gas production at a weighted average price of $4.05 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.

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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.

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. Most 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 or, in the case of the Utica Shale, management expectations, would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our gross 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, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, 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 a result of the limitations described above, we may be unable to drill many of our drilling locations. As a result of the limitations described above, we may be unable to drill many of our drilling locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

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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, 2013, on a pro forma basis, we had leases representing 1,054 undeveloped acres scheduled to expire in 2014, 2,365 undeveloped acres scheduled to expire in 2015, 4,132 undeveloped acres scheduled to expire in 2016, 35,639 undeveloped acres scheduled to expire in 2017 and 28,161 undeveloped acres scheduled to expire in 2018 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. In addition, in order to hold our current leases scheduled to expire in 2014 and 2015, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy rigs when needed, or that commodity prices will warrant operating such a drilling program. 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, 2013, 2012 and 2011, 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. 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 limited liability company, our predecessor was not subject to federal taxation. Accordingly, our standardized measure does not provide for federal corporate income taxes because taxable income was passed through to its members. 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 prospectus 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

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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, 2013, approximately 58% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 352 Bcf of pro forma estimated proved undeveloped reserves will require an estimated $313 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 natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

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

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand

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for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, we enter into derivative instrument contracts for a significant portion of our natural gas production, including fixed-price swaps. As of December 31, 2013, we had entered into hedging contracts through December 31, 2017 covering a total of approximately 186 Bcf of our projected natural gas production at a weighted average price of $4.09 per MMBtu. For the period from January 1, 2014 until December 31, 2014, we have hedged approximately 62.9 Bcf of our projected natural gas production at a weighted average price of $4.05 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 May 1, 2014, the estimated fair value of our commodity derivative contracts was approximately $4.0 million. Any default by the counterparties to these derivative contracts, Wells Fargo Bank N.A. and Bank of Montreal, when they become due would have a material adverse effect on our financial condition and results of operations. In addition to the counterparties above at December 31, 2013, subsequent to December 31, 2013, we also executed hedging transactions with Barclays Bank PLC.

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 ($82.2 million as of September 30, 2014) and the sale of our natural gas production ($52.3 million in receivables as of September 30, 2014), which we market to multiple natural gas marketing companies. 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.

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The largest purchaser of our natural gas during the three months ended September 30, 2014 represented approximately 87% 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:

- Clean Air Act (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;
- Comprehensive Environmental Response, Compensation, and Liability Act (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;
- Resource Conservation and Recovery Act (RCRA), and analogous state law, which impose requirements for the handling and disposal of any solid and hazardous waste from our facilities;
- National Environmental Policy Act (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;
- Safe Drinking Water Act (SDWA), and analogous state law, which restrict the disposal, treatment or release of water produced or used during oil and gas development;
- Endangered Species Act (ESA), and analogous state law, which seek to ensure that activities do not jeopardize endangered or threatened animals and plant species, nor destroy or modify the critical habitat of such species; and
- Oil Pollution Act (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 (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.

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 alleged potential impacts to the environment due to hydraulic fracturing, 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 . However, Congress has from time to time considered legislation that would amend the SDWA to 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.

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In February 2014, the EPA asserted federal regulatory authority under the SDWA s UIC program over hydraulic fracturing involving diesel additives, and requested comments in May 2014 on a proposal to require disclosure of chemical ingredients in hydraulic fracturing fluids under the Toxic Substances Control Act. Because EPA s Advanced Notice of Proposed Rulemaking did not propose any actual regulation, it is unclear how any federal disclosure requirements that add to any applicable state disclosure requirements already in effect may affect our operations. Further, on October 21, 2011, the EPA announced its intention to propose federal CWA regulations governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the U.S. Department of the Interior published a Supplemental Notice of Proposed Rulemaking on May 16, 2013 that would update existing regulation of hydraulic fracturing activities on federal and Indian lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. Studies by the EPA and other federal agencies are underway that focus on the environmental aspects of hydraulic fracturing activities, with draft reports expected for public comment and peer review in late 2014. These studies could spur further regulation. Additional regulations adopted at the federal or state level could result in permitting delays and cost increases.

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 and Ohio (where we conduct operations) have 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. In Pennsylvania, although the 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 adopt ordinances regulating 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.

Restrictions on our ability to obtain, use, manage or dispose of water may have an adverse effect on 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 and similar state laws impose restrictions and strict controls on the discharge of produced waters and other natural gas and oil waste where such discharges could affect surface or ground waters. For example, state and federal 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. We must obtain permits for certain discharges into waters and wetlands and for construction activities that may affect regulated water resources. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. The CWA and similar state laws provide for civil, criminal and/or administrative penalties for any unauthorized discharges of pollutants, reportable quantities of oil and other hazardous substances. Moreover, sending wastewater to publicly-owned treatment works in Pennsylvania and Ohio requires certain levels of pretreatment that may effectively prohibit such disposal, 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. Compliance with current and future federal, state and local 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 accurately predicted.

We are subject to risks associated with climate change.

Climate change, the costs that may be associated with its effects and the regulation of greenhouse gases (GHGs) have the potential to affect our business in many ways, including increasing the costs to provide our products and services, reducing 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 may increase our operating costs. 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, in June 2013, the Obama Administration 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.

In September 2009, the EPA finalized a mandatory 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 to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent (CO2e) emissions per year and to most upstream suppliers of fossil fuels, as well as manufacturers of vehicles and engines. Subsequently, in November 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 CO2e per year. The rule required 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. The EPA also issued a final rule that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions, beginning in 2011, under the CAA. However, in June 2014, the U.S. Supreme Court, in UARG v. EPA, limited the application of the GHG permitting requirements under the Prevention of Significant deterioration and Title V permitting programs to sources that would otherwise need permits based on the emission of conventional pollutants.

Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the passage of any federal or state climate change laws or regulations in the future 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.

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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.

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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 cancelled as a result of numerous factors, including:

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

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

In the future we may make acquisitions of businesses that complement or expand our current business. 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.

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

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

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

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

Our natural gas exploration, production and transportation operations are subject to complex and stringent federal, state and local laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations and the permits and other approvals issued thereunder. In addition, our costs of compliance may increase or operational delays may occur if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations. Also, we might not be able to obtain or maintain all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs.

In addition, new or additional regulations or permitting requirements, new interpretations of requirements or changes in our operations could also trigger the need for Environmental Assessments or more detailed Environmental Impact Statements under NEPA and analogous state laws, as well as litigation over the adequacy of those reviews, which could result in increased costs or delays of, or denial of rights to conduct, our development programs. Such potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our business, financial condition and results of operations. Further, the discharges of oil, natural gas, NGLs and other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties. See Business Regulation of Environmental and Occupational Safety and Health Matters for a further description of laws and regulations that affect us.

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

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. We intend to continue our four-rig drilling program in the Marcellus Shale and two-rig drilling program in the Utica Shale; however, certain of the rigs performing work for us do so on a well-by-well basis and can refuse to provide such services at the conclusion of drilling on the current well. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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

Section 1(b) of the Natural Gas Act of 1938, (NGA), exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission (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. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation, the rates for, and terms and conditions of services provided by such facility would be subject to regulation by the FERC. Such regulation could decrease revenues, increase operating costs, and depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the cost-based rate established by the FERC.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. We cannot predict what new or different regulations federal and state regulatory agencies may adopt, or what effect subsequent regulation may have on our activities. Such regulations may have a material adverse effect on our financial condition, result of operations and cash flows.

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

Under the Energy Policy Act of 2005 (EPAct 2005), FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC as a natural gas company under the NGA, we are required to report aggregate volumes of natural gas purchased or sold at wholesale to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. In addition, Congress may enact legislation or FERC may adopt regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to further regulation. Failure to comply with those regulations in the future could subject us to civil penalty liability.

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and

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retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We are susceptible to the potential difficulties associated with rapid growth and expansion and have a limited operating history.

We have grown rapidly over the last several years and more than doubled our employee workforce during 2013. Our management believes that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burden;
- increased capital requirements; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information included herein is not necessarily indicative of the results that may be realized in the future. In addition, our operating history is limited and the results from our current producing wells are not necessarily indicative of success from our future drilling operations. We began development of our properties in 2010 with a two-rig drilling program. Recently, we expanded our development operations and are currently managing a six-rig drilling program. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

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

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

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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

The successful acquisition of producing and undeveloped 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.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review may neither reveal all existing or potential problems nor permit us to fully assess the environmental and other liabilities of the properties. Inspections may not always be performed on every well or pipeline, and environmental and structural problems, such as groundwater contamination and pipe corrosion, are not necessarily observable during an inspection. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the liabilities created prior to the purchase of our property. Moreover, we often acquire properties on an as is basis and, thus, are not entitled to contractual indemnification for environmental liabilities.

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized some regulations, including critical rulemakings on the definition of swap, swap dealer, and major swap participant , others remain to be finalized and it is not possible at this time to predict when this will be accomplished.

The Dodd-Frank Act authorized the CFTC to establish rules and regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The CFTC s initial position limits rules were vacated by the U.S. District Court for the District of Columbia in September 2012. However, on November 5, 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for swaps entered to hedge its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce our cash available for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to us is uncertain at this time.

The Dodd-Frank Act and regulations may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is lower commodity prices.

Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations.

In February 2012, the state legislature of Pennsylvania passed a new natural gas impact fee in Pennsylvania. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. The fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices from the last day of each month. There can be no assurance that the impact fee will remain as currently structured or that new or additional taxes will not be imposed.

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

The Fiscal Year 2015 Budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress that would implement many of these proposals. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

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

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

Risks Related to Exchange Offer

If you do not properly tender your old notes, you will continue to hold unregistered old notes and your ability to transfer old notes will remain restricted and may be adversely affected.

We will only issue new notes in exchange for old notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the old notes and you should carefully follow the instructions on how to tender your old notes. Neither we nor the exchange agent is required to tell you of any defects or irregularities with respect to your tender of old notes.

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If you do not exchange your old notes for new notes pursuant to the exchange offer, the old notes you hold will continue to be subject to the existing transfer restrictions. In general, you may not offer or sell the old notes except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not plan to register old notes under the Securities Act unless our registration rights agreement with the initial purchasers of the old notes require us to do so. Further, if you continue to hold any old notes after the exchange offer is consummated, you may have trouble selling them because there will be fewer of these notes outstanding.

Risks Related to the Notes

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

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

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our revolving credit facility currently restricts our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

The borrowing base under our revolving credit facility is currently $550.0 million. Our next scheduled borrowing base redetermination is expected to occur in April 2015. In the future, we may not be able to access adequate funding under our revolving credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender s portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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Our leverage and debt service obligations may adversely affect our financial condition, results of operations, business prospects and our ability to make payments on the notes.

As of September 30, 2014, we and our subsidiaries had approximately $901.0 million of outstanding indebtedness, including no borrowings under our revolving credit facility, $66.8 million of outstanding letters of credit, and we had approximately $318.2 million of borrowing capacity under our revolving credit facility. Our level of indebtedness could affect our operations in several ways, including the following:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities;

- limit management s discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;

- increase our vulnerability to downturns and adverse developments in our business and the economy generally;

- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;

- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

- make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings;

- make us vulnerable to increases in interest rates as our indebtedness under any revolving credit facility may vary with prevailing interest rates;

- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and

- make it more difficult for us to satisfy our obligations under the notes or other debt and increase the risk that we may default on our debt obligations.

The notes and the guarantees are unsecured obligations and are effectively subordinated to all of our existing and future secured indebtedness and structurally subordinated to liabilities of any non-guarantor subsidiaries.

The notes and the guarantees are general unsecured senior obligations ranking effectively junior to all of our existing and future secured indebtedness (including all borrowings under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness. If we or a guarantor is declared bankrupt, becomes insolvent or is liquidated or reorganized, the holders of our secured indebtedness or the secured indebtedness of such guarantor will be entitled to be paid in full from the proceeds of the assets, if any, securing such indebtedness before any payment may be made with respect to the notes or the affected guarantees. Holders of the notes will participate ratably in any remaining proceeds with all holders of our unsecured indebtedness, including unsecured indebtedness incurred after the notes are issued that does not rank junior to the notes, including trade payables and all of our other general indebtedness, based on the respective amounts owed to each holder or creditor. In any of the foregoing events, there may not be sufficient funds to pay amounts due on the notes. As a result, holders of the notes would likely receive less, ratably, than holders of secured indebtedness.

The notes are structurally subordinated to any indebtedness and other liabilities of any subsidiaries that do not guarantee the notes. The indenture governing the notes permits us to form or acquire additional subsidiaries that are not guarantors of the notes in certain circumstances.

Holders of the notes will have no claim as a creditor against any of our non-guarantor subsidiaries. See Description of Notes Brief Description of the Notes and Subsidiary Guarantees The Subsidiary Guarantees.

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We and the guarantors may incur substantial additional indebtedness. This could increase the risks associated with the notes.

Subject to the restrictions in the indenture governing the notes and in other instruments governing our other outstanding indebtedness (including our revolving credit facility), we and our subsidiaries may incur substantial additional indebtedness (including secured indebtedness) in the future. Although the indenture governing the notes and our revolving credit facility contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial.

If we or a guarantor incurs any additional indebtedness that ranks equally with the notes (or with the guarantees thereof), including additional unsecured indebtedness or trade payables, the holders of that indebtedness will be entitled to share ratably with holders of the notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us or a guarantor. This may have the effect of reducing the amount of proceeds paid to holders of the notes in connection with such a distribution.

Any increase in our level of indebtedness will have several important effects on our future operations, including, without limitation, whether:

- we will have additional cash requirements in order to support the payment of interest on our outstanding indebtedness;
- increases in our outstanding indebtedness and leverage will increase our vulnerability to adverse changes in general economic and industry conditions, as well as to competitive pressure; and
- depending on the levels of our outstanding indebtedness, our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes may be limited.

We cannot assure you that we will be able to maintain or improve our leverage position.

An element of our business strategy involves maintaining a disciplined approach to financial management. However, we are also seeking to acquire, exploit and develop additional reserves which may require the incurrence of additional indebtedness. Although we will seek to maintain or improve our leverage position, our ability to maintain or reduce our level of indebtedness depends on a variety of factors, including future performance and our future debt financing needs. General economic conditions, oil, NGL and natural gas prices and financial, business and other factors will also affect our ability to maintain or improve our leverage position. Many of these factors are beyond our control.

Our revolving credit facility and the indenture governing the notes have restrictive covenants that could limit our financial flexibility. Our revolving credit facility and the indenture governing the notes contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under our revolving credit facility is subject to compliance with certain financial covenants, including the maintenance of certain financial ratios, including a minimum current ratio, an asset coverage ratio and a minimum interest coverage ratio. Our revolving credit facility and the indenture governing the notes contain covenants, that, among other things, limit our ability and the ability of our restricted subsidiaries to:

incur additional indebtedness;

sell assets;

pay dividends or make certain investments;

create liens that secure indebtedness;

enter into transactions with affiliates; and

merge or consolidate with another company.

See Description of Notes Certain Covenants. Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. We would not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

The borrowing base under our revolving credit facility is subject to periodic redetermination.

The borrowing base under our revolving credit facility is redetermined at least semi-annually. The administrative agent under the revolving credit facility may elect to cause interim redeterminations under certain circumstances. In addition, we and the administrative agent may each request one additional redetermination in each 12-month period. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. In addition, our lenders have substantial flexibility to reduce our borrowing base due to subjective factors. As of December 31, 2013, our borrowing base was $350.0 million. In October 2014 we had a redetermination of our borrowing base under our revolving credit facility which increased the borrowing base to $550.0 million. The next redetermination is scheduled for April 2015. We could be required to repay a portion of our bank debt to the extent that after a redetermination our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans thereunder requiring us to negotiate renewals, arrange new financing or sell significant assets, all of which could have a material adverse effect on our business and financial results.

If we are unable to comply with the restrictions and covenants in the agreements governing the notes and our other indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and would affect our ability to make principal and interest payments on the notes.

Any default under the agreements governing our indebtedness that is not cured or waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make us unable to pay principal, premium, if any, and interest, or special interest, if any, on the notes and substantially decrease the market value of the notes. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest, or special interest, if any, on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the agreements governing our indebtedness (including covenants in our revolving credit facility and the indenture governing the notes), we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders under our revolving credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers under our revolving credit facility to avoid being in default. If we breach our covenants under our revolving credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under the facilities, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

We may not be able to repurchase the notes upon a change of control.

If we experience certain kinds of changes of control followed by a rating decline, we may be required to offer to repurchase all outstanding notes at 101% of their principal amount plus accrued and unpaid interest, if any. We may not be able to repurchase the notes upon a change of control because we may not have sufficient financial resources to purchase all of the notes that are tendered following a change of control. In addition, the terms of our revolving credit facility would prohibit, and the terms of other future indebtedness may prohibit, us from repurchasing notes upon a change of control. Our failure to repurchase the notes upon a change of control could cause a default under the indenture governing the notes and could lead to a cross default under our revolving credit facility. Additionally, using cash to fund the potential consequences of a change of control may impair our ability to obtain additional financing in the future, which could negatively impact our ability to conduct our business operations. See Description of Notes Repurchase at the Option of Holders Change of Control.

Federal and state statutes allow courts, under specific circumstances, to void guarantees and require noteholders to return payments received from guarantors.

Federal bankruptcy and state fraudulent transfer laws permit a court to avoid all or a portion of the obligations of a guarantor pursuant to its guarantee of the notes, or to subordinate any guarantor s obligations under such guarantee to claims of its other creditors, reducing or eliminating the noteholders ability to recover under such guarantee. Although laws differ among these jurisdictions, in general, under applicable fraudulent transfer or conveyance laws, a guarantee could be voided as a fraudulent transfer or conveyance if (i) the guarantee was incurred with the intent of hindering, delaying or defrauding creditors; or (ii) the guarantor received less than reasonably equivalent value or fair consideration in return for incurring the guarantee and either:

- the guarantor was insolvent or rendered insolvent by reason of the incurrence of the guarantee or subsequently became insolvent for other reasons;
- the incurrence of the guarantee left the guarantor with an unreasonably small amount of capital to carry on the business; or
- the guarantor intended to, or believed that it would, incur debts beyond its ability to pay such debts as they mature.

A court would likely find that a guarantor did not receive reasonably equivalent value or fair consideration for its guarantee if the guarantor did not substantially benefit directly or indirectly from the issuance of the notes. If a court were to void a guarantee, you would no longer have a claim against the guarantor. Sufficient funds to repay the notes may not be available from other sources, including the remaining guarantors, if any. In addition, the court might direct you to repay any amounts that you already received from the guarantor. The measures of insolvency for purposes of fraudulent transfer laws vary depending upon the governing law of the applicable jurisdiction. Generally, a guarantor would be considered insolvent if:

- the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all its assets;
- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they became absolute and mature; or

it could not pay its debts as they became due.

Each guarantee will contain a provision intended to limit the guarantor s liability under the guarantee to the maximum amount that the guarantor could incur without causing the incurrence of obligations under its guarantee to be deemed a fraudulent transfer. This provision may not be effective to protect the guarantees from being voided under fraudulent transfer law.

Many of the covenants contained in the indenture will be terminated if the notes are rated investment grade by Standard & Poor s and Moody s and no default has occurred and is continuing.

Many of the covenants in the indenture governing the notes will be terminated if the notes are rated investment grade by Standard & Poor s and Moody s, provided at such time no default or event of default has occurred and is continuing. These covenants include restrictions on our ability to pay dividends, to incur debt and to enter into certain transactions. There can be no assurance that the notes will ever be rated investment grade. However, termination of these covenants would allow us to engage in certain transactions that would not have been permitted while these covenants were in force. The covenant termination will continue even if the notes are subsequently downgraded below investment grade. See Description of Notes Certain Covenants Covenant Termination.

We face risks related to rating agency downgrades.

We expect one or more rating agencies to rate the notes. If such rating agencies either assign the notes a rating lower than the rating expected by the investors, or reduce the rating in the future, the market price of the notes may be adversely affected, raising capital may become more difficult and borrowing costs under our revolving credit facility and other future borrowings may increase.

Your ability to transfer the notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop for the notes.

The old notes have not been registered under the Securities Act, and may not be resold by purchasers thereof unless the old notes are subsequently registered or an exemption from the registration requirements of the Securities Act is available. However, we cannot assure you that, even following registration or exchange of the old notes for new notes, that an active trading market for the old notes or the new notes will exist, and we will have no obligation to create such a market. At the time of the private placement of the old notes, the initial purchasers advised us that they intended to make a market in the old notes and, if issued, the new notes. The initial purchasers are not obligated, however, to make a market in the old notes or the new notes and any market-making may be discontinued at any time at their sole discretion. No assurance can be given as to the liquidity of or trading market for the old notes or the new notes.

The liquidity of any trading market for the notes and the market price quoted for the notes will depend upon the number of holders of the notes, the overall market for high yield securities, our financial performance or prospects or the prospects for companies in our industry generally, the interest of securities dealers in making a market in the notes and other factors.

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EXCHANGE OFFER

Purpose and Effect of the Exchange Offer

At the closing of the offering of the old notes, we entered into a registration rights agreement with the initial purchasers pursuant to which we agreed, for the benefit of the holders of the old notes, at our cost, to do the following:

- file an exchange offer registration statement with the SEC with respect to the exchange offer for the new notes,

- use reasonable best efforts to cause the exchange offer registration statement to be declared effective under the Securities Act, and

- use reasonable best efforts to have the exchange offer completed by the 365th day following the date of the initial issuance of the notes (April 25, 2015).

Upon the SEC s declaring the exchange offer registration statement effective, we agreed to offer the new notes in exchange for surrender of the old notes. We agreed to use reasonable best efforts to cause the exchange offer registration statement to be effective continuously, to keep the exchange offer open for a period of not less than 20 business days and to use reasonable best efforts to cause the exchange offer to be commenced promptly after the exchange offer registration statement is declared effective by the SEC.

For each old note surrendered to us pursuant to the exchange offer, the holder of such old note will receive a new note having a principal amount equal to that of the surrendered old note. Interest on each new note will accrue from the last interest payment date on which interest was paid on the surrendered old note, November 1, 2014. The registration rights agreement also obligates us to include in the prospectus for the exchange offer certain information necessary to allow a broker-dealer who holds old notes that were acquired for its own account as a result of market-making activities or other ordinary course trading activities (other than old notes acquired directly from us or one of our affiliates) to exchange such old notes pursuant to the exchange offer and to satisfy the prospectus delivery requirements in connection with resales of new notes received by such broker-dealer in the exchange offer. We agreed to amend or supplement the prospectus contained in the exchange offer registration statement for a period of 180 days after the last exchange date, which period may be extended under certain circumstances.

The preceding agreement is needed because any broker-dealer who acquires old notes for its own account as a result of market-making activities or other trading activities is required to deliver a prospectus meeting the requirements of the Securities Act. This prospectus covers the offer and sale of the new notes pursuant to the exchange offer and the resale of new notes received in the exchange offer by any broker-dealer who held old notes acquired for its own account as a result of market-making activities or other trading activities other than old notes acquired directly from us or one of our affiliates.

Based on interpretations by the staff of the SEC set forth in no-action letters issued to third parties, we believe that the new notes issued pursuant to the exchange offer would in general be freely tradable after the exchange offer without further registration under the Securities Act. However, any purchaser of old notes who is an affiliate of ours or who intends to participate in the exchange offer for the purpose of distributing the related new notes:

will not be able to rely on the interpretation of the staff of the SEC,

will not be able to tender its old notes in the exchange offer, and

must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the old notes unless such sale or transfer is made pursuant to an exemption from such requirements.

Each holder of the old notes (other than certain specified holders) who desires to exchange old notes for the new notes in the exchange offer will be required to make the representations described below under Procedures for Tendering Your Representations to Us.

We further agreed to file with the SEC a shelf registration statement to register for public resale of old notes held by any holder who provides us with certain information for inclusion in the shelf registration statement if:

i. the exchange offer would violate any applicable law or applicable interpretation of the staff of the SEC,

ii. the exchange offer is not consummated within 365 days of the issuance of the old notes,

iii. any initial purchaser so requests with respect to the old notes not eligible to be exchanged for the new notes and held by it following the consummation of the exchange offer, or

iv. any holder, other than a broker-dealer, is not eligible to participate in the exchange offer, or if any holder, other than a broker-dealer, that participates in the exchange offer does not receive freely tradeable new notes in exchange for tendered old notes.

We have agreed, at our expense, (a) as promptly as practicable (but in no event more than 30 days after such filing obligation arises) file a shelf registration statement, (b) to use our reasonable best efforts to cause the shelf registration statement to be declared effective (unless it becomes effective automatically upon filing) under the Securities Act on or prior to April 25, 2015 in the case of clauses (i) and (ii) above and on or prior to the 180th day after the date on which the shelf registration statement is required to be filed in the case of clauses (iii) and (iv) above, and (c) to keep effective the shelf registration statement until two years after its effective date (or such shorter period that will terminate when all the notes covered thereby have been sold pursuant thereto or in certain other circumstances).

If (a) the exchange offer is not consummated on or before to the 365th calendar day following the date of issuance of the old notes, (b) a shelf registration statement applicable to the notes is not filed or declared effective when required, or (c) a registration statement applicable to the notes is declared effective as required but thereafter fails to remain effective or usable in connection with resales for more than 60 days (each such event referred to in clauses (a) through (c) above, a Registration Default), we will pay liquidated damages in the form of additional interest in cash to each holder of notes in an amount equal to 0.25% per annum of the aggregate principal amount of notes for the 90-day period immediately following the occurrence of the Registration Default until such time as no Registration Default is in effect, which rate shall increase by 0.25% per annum for each subsequent 90-day period during which such Registration Default continues up to a maximum of 1.00% per annum. Following the cure of all Registration Defaults, such additional interest will cease to accrue and the interest rate on the notes will revert to the original rate; provided, however, that, if after the date such additional interest ceases to accrue, a different Registration Default occurs, such additional interest may again commence accruing pursuant to the foregoing provisions. All references herein to interest include any additional interest payable pursuant to this paragraph.

Holders of the old notes will be required to make certain representations to us (as described in the registration rights agreement) in order to participate in the exchange offer and may be required to deliver information to be used in connection with the shelf registration statement and to provide comments on the shelf registration statement within the time periods set forth in the registration rights agreement in order to have their old notes included in the shelf registration statement.

This summary of the material provisions of the registration rights agreement does not purport to be complete and is subject to, and is qualified in its entirety by reference to, all the provisions of the registration rights agreement, copies of which are filed as exhibits to the registration statement which includes this prospectus.

Except as set forth above, after consummation of the exchange offer, holders of old notes which are the subject of the exchange offer have no registration or exchange rights under the registration rights agreement. See Consequences of Failure to Exchange.

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Terms of the Exchange Offer

Subject to the terms and conditions described in this prospectus and in the letter of transmittal, we will accept for exchange any old notes properly tendered and not withdrawn prior to 5:00 p.m., New York City time, on the expiration date. We will issue new notes in principal amount equal to the principal amount of old notes surrendered in the exchange offer. Old notes may be tendered only for new notes and only in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The exchange offer is not conditioned upon any minimum aggregate principal amount of old notes being tendered for exchange.

As of the date of this prospectus, $900,000,000 in aggregate principal amount of the old notes is outstanding. This prospectus and the letter of transmittal are being sent to all registered holders of old notes. There will be no fixed record date for determining registered holders of old notes entitled to participate in the exchange offer.

We intend to conduct the exchange offer in accordance with the provisions of the registration rights agreement, the applicable requirements of the Securities Act and the Securities Exchange Act of 1934 and the rules and regulations of the SEC. Old notes that the holders thereof do not tender for exchange in the exchange offer will remain outstanding and continue to accrue interest. These old notes will continue to be entitled to the rights and benefits such holders have under the indenture relating to the notes and the registration rights agreement.

We will be deemed to have accepted for exchange properly tendered old notes when we have given oral or written notice of the acceptance to the exchange agent and complied with the applicable provisions of the registration rights agreement. The exchange agent will act as agent for the tendering holders for the purposes of receiving the new notes from us.

If you tender old notes in the exchange offer, you will not be required to pay brokerage commissions or fees or, subject to the letter of transmittal, transfer taxes with respect to the exchange of old notes. We will pay all charges and expenses, other than certain applicable taxes described below, in connection with the exchange offer. It is important that you read the section labeled Fees and Expenses for more details regarding fees and expenses incurred in the exchange offer.

We will return any old notes that we do not accept for exchange for any reason without expense to their tendering holder promptly after the expiration or termination of the exchange offer.

Expiration Date

The exchange offer will expire at 5:00 p.m., New York City time, on , 2014, unless, in our sole discretion, we extend it.

Extensions, Delays in Acceptance, Termination or Amendment

We expressly reserve the right, at any time or various times, to extend the period of time during which the exchange offer is open. We may delay acceptance of any old notes by giving oral or written notice of such extension to their holders. During any such extensions, all old notes previously tendered will remain subject to the exchange offer, and we may accept them for exchange.

In order to extend the exchange offer, we will notify the exchange agent orally or in writing of any extension. We will notify the registered holders of old notes of the extension no later than 9:00 a.m., New York City time, on the business day after the previously scheduled expiration date.

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If any of the conditions described below under Conditions to the Exchange Offer have not been satisfied, we reserve the right, in our sole discretion:

- to delay accepting for exchange any old notes,
- to extend the exchange offer, or
- to terminate the exchange offer,

by giving oral or written notice of such delay, extension or termination to the exchange agent. Subject to the terms of the registration rights agreement, we also reserve the right to amend the terms of the exchange offer in any manner.

Any such delay in acceptance, extension, termination or amendment will be followed promptly by oral or written notice thereof to the registered holders of old notes. If we amend the exchange offer in a manner that we determine to constitute a material change, we will promptly disclose such amendment by means of a prospectus supplement. The supplement will be distributed to the registered holders of the old notes. Depending upon the significance of the amendment and the manner of disclosure to the registered holders, we may extend the exchange offer. In the event of a material change in the exchange offer, including the waiver by us of a material condition, we will extend the exchange offer period if necessary so that at least five business days remain in the exchange offer following notice of the material change.

Conditions to the Exchange Offer

We will not be required to accept for exchange, or exchange any new notes for, any old notes if the exchange offer, or the making of any exchange by a holder of old notes, would violate applicable law or any applicable interpretation of the staff of the SEC. Similarly, we may terminate the exchange offer as provided in this prospectus before accepting old notes for exchange in the event of such a potential violation.

In addition, we will not be obligated to accept for exchange the old notes of any holder that has not made to us the representations described under Purpose and Effect of the Exchange Offer, Procedures for Tendering and Plan of Distribution and such other representations as may be reasonably necessary under applicable SEC rules, regulations or interpretations to allow us to use an appropriate form to register the new notes under the Securities Act.

We expressly reserve the right to amend or terminate the exchange offer, and to reject for exchange any old notes not previously accepted for exchange, upon the occurrence of any of the conditions to the exchange offer specified above. We will give prompt oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the old notes as promptly as practicable.

These conditions are for our sole benefit, and we may assert them or waive them in whole or in part at any time or at various times in our sole discretion. If we fail at any time to exercise any of these rights, this failure will not mean that we have waived our rights. Each such right will be deemed an ongoing right that we may assert at any time or at various times.

In addition, we will not accept for exchange any old notes tendered, and will not issue new notes in exchange for any such old notes, if at such time any stop order has been threatened or is in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the indenture relating to the notes under the Trust Indenture Act of 1939.

Procedures for Tendering

In order to participate in the exchange offer, you must properly tender your old notes to the exchange agent as described below. It is your responsibility to properly tender your notes. We have the right to waive any defects. However, we are not required to waive defects and are not required to notify you of defects in your tender.

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If you have any questions or need help in exchanging your notes, please call the exchange agent, whose address and phone number are set forth in Prospectus Summary The Exchange Offer Exchange Agent.

All of the old notes were issued in book-entry form, and all of the old notes are currently represented by global certificates held for the account of DTC. We have confirmed with DTC that the old notes may be tendered using the Automated Tender Offer Program (ATOP) instituted by DTC. The exchange agent will establish an account with DTC for purposes of the exchange offer promptly after the commencement of the exchange offer and DTC participants may electronically transmit their acceptance of the exchange offer by causing DTC to transfer their old notes to the exchange agent using the ATOP procedures. In connection with the transfer, DTC will send an agent s message to the exchange agent. The agent s message will state that DTC has received instructions from the participant to tender old notes and that the participant agrees to be bound by the terms of the letter of transmittal.

By using the ATOP procedures to exchange old notes, you will not be required to deliver a letter of transmittal to the exchange agent. However, you will be bound by its terms just as if you had signed it.

There is no procedure for guaranteed late delivery of the notes.

Determinations Under the Exchange Offer

We will determine in our sole discretion all questions as to the validity, form, eligibility, time of receipt, acceptance of tendered old notes and withdrawal of tendered old notes. Our determination will be final and binding. We reserve the absolute right to reject any old notes not properly tendered or any old notes our acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defect, irregularities or conditions of tender as to particular old notes. Our interpretation of the terms and conditions of the exchange offer, including the instructions in the letter of transmittal, will be final and binding on all parties. Unless waived, all defects or irregularities in connection with tenders of old notes must be cured within such time as we shall determine. Although we intend to notify holders of defects or irregularities with respect to tenders of old notes, neither we, the exchange agent nor any other person will incur any liability for failure to give such notification. Tenders of old notes will not be deemed made until such defects or irregularities have been cured or waived. Any old notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned to the tendering holder, unless otherwise provided in the letter of transmittal, promptly following the expiration date.

When We Will Issue New Notes

In all cases, we will issue new notes for old notes that we have accepted for exchange under the exchange offer only after the exchange agent timely receives:

- a book-entry confirmation of such old notes into the exchange agent s account at DTC; and

- a properly transmitted agent s message.

Return of Old Notes Not Accepted or Exchanged

If we do not accept any tendered old notes for exchange or if old notes are submitted for a greater principal amount than the holder desires to exchange, the unaccepted or non-exchanged old notes will be returned without expense to their tendering holder. Such non-exchanged old notes will be credited to an account maintained with DTC. These actions will occur promptly after the expiration or termination of the exchange offer.

Your Representations to Us

By agreeing to be bound by the letter of transmittal, you will represent to us that, among other things:

- any new notes that you receive will be acquired in the ordinary course of your business;
- you have no arrangement or understanding with any person or entity to participate in the distribution of the new notes;

- you are not our affiliate, as defined in Rule 405 of the Securities Act; and

- if you are a broker-dealer that will receive new notes for your own account in exchange for old notes, you acquired those notes as a result of market-making activities or other trading activities and you will deliver a prospectus (or to the extent permitted by law, make available a prospectus) in connection with any resale of such new notes.

Withdrawal of Tenders

Except as otherwise provided in this prospectus, you may withdraw your tender at any time prior to 5:00 p.m., New York City time, on the expiration date. For a withdrawal to be effective you must comply with the appropriate procedures of DTC s ATOP system. Any notice of withdrawal must specify the name and number of the account at DTC to be credited with withdrawn old notes and otherwise comply with the procedures of DTC.

We will determine all questions as to the validity, form, eligibility and time of receipt of notice of withdrawal. Our determination shall be final and binding on all parties. We will deem any old notes so withdrawn not to have been validly tendered for exchange for purposes of the exchange offer.

Any old notes that have been tendered for exchange but are not exchanged for any reason will be credited to an account maintained with DTC for the old notes. This crediting will take place as soon as practicable after withdrawal, rejection of tender or termination of the exchange offer. You may retender properly withdrawn old notes by following the procedures described under Procedures for Tendering above at any time prior to 5:00 p.m., New York City time, on the expiration date.

Fees and Expenses

We will bear the expenses of soliciting tenders. The principal solicitation is being made by mail; however, we may make additional solicitation by facsimile, telephone, electronic mail or in person by our officers and regular employees and those of our affiliates.

We have not retained any dealer-manager in connection with the exchange offer and will not make any payments to broker-dealers or others soliciting acceptances of the exchange offer. We will, however, pay the exchange agent reasonable and customary fees for its services and reimburse it for its related reasonable out-of-pocket expenses.

We will pay the cash expenses to be incurred in connection with the exchange offer. They include:

- all registration and filing fees and expenses;

- all fees and expenses of compliance with federal securities and state blue sky or securities laws;

- accounting and legal fees, disbursements and printing, messenger and delivery services, and telephone costs; and related fees and expenses.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchange of old notes under the exchange offer. The tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if a transfer tax is imposed for any reason other than the exchange of old notes under the exchange offer.

Consequences of Failure to Exchange

If you do not exchange new notes for your old notes under the exchange offer, you will remain subject to the existing restrictions on transfer of the old notes. In general, you may not offer or sell the old notes unless the offer or sale is either registered under the Securities Act or exempt from the registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreement, we do not intend to register resales of the old notes under the Securities Act.

Accounting Treatment

We will record the new notes in our accounting records at the same carrying value as the old notes. This carrying value is the aggregate principal amount of the old notes less any bond discount, as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes in connection with the exchange offer.

Other

Participation in the exchange offer is voluntary, and you should carefully consider whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered old notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any old notes that are not tendered in the exchange offer or to file a registration statement to permit resales of any untendered old notes.

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USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreement. We will not receive any proceeds from the issuance of the new notes in the exchange offer. In consideration for issuing the new notes as contemplated by this prospectus, we will receive old notes in a like principal amount. The form and terms of the new notes are identical in all respects to the form and terms of the old notes, except the new notes will be registered under the Securities Act and will not contain restrictions on transfer, registration rights or provisions for additional interest. Old notes surrendered in exchange for the new notes will be retired and cancelled and will not be reissued. Accordingly, the issuance of the new notes will not result in any change in outstanding indebtedness.

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SELECTED HISTORICAL CONSOLIDATED AND UNAUDITED PRO FORMA FINANCIAL DATA

The following table shows selected historical consolidated financial data of Rice Energy Inc. and the summary unaudited pro forma financial data for the periods and as of the dates indicated. Our historical results are not necessarily indicative of future operating results. The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes included elsewhere herein.

The selected historical consolidated financial data as of and for the years ended December 31, 2011, 2012 and 2013 are derived from the audited consolidated financial statements of Rice Energy included elsewhere in this prospectus. The summary historical consolidated statement of operations data for each of the nine month periods ended September 30, 2013 and 2014 and the historical consolidated balance sheet data as of September 30, 2014 are derived from the unaudited consolidated financial statements of Rice Energy Inc. included elsewhere in this prospectus. The selected historical unaudited historical consolidated interim financial data has been prepared on a consistent basis with the audited consolidated financial statements of Rice Energy. In the opinion of management, such selected unaudited historical consolidated financial interim data reflects all adjustments (consisting of normal and recurring accruals) considered necessary to present our financial position for the periods presented. The results of operations for the interim periods are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received from oil and natural gas, natural production declines, the uncertainty of exploration and development drilling results and other factors.

The summary unaudited pro forma consolidated statements of operations data for the year ended December 31, 2013 and nine months ended September 30, 2014 has been prepared to give pro forma effect to (i) the Marcellus JV Buy-In and (ii) our IPO and the application of the net proceeds therefrom as if each had been completed as of January 1, 2013. Each of our IPO and the Marcellus JV Buy-In was completed prior to September 30, 2014 and is thus fully reflected in our historical consolidated balance sheet as of such date. The summary unaudited pro forma consolidated statements of operations data do not give pro forma effect to our April 2014 acquisition of certain gas gathering assets in eastern Washington and Greene Counties, Pennsylvania, the Senior Notes Offering, the Greene County Acquisition or our August 2014 equity offering. These data are subject and give effect to the assumptions and adjustments described in the notes accompanying the unaudited pro forma financial statements included elsewhere in this prospectus. The summary unaudited pro forma consolidated financial data are presented for informational purposes only and should not be considered indicative of actual results of operations that would have been achieved had (i) the Marcellus JV Buy-In and (ii) our IPO and the application of the net proceeds therefrom been completed as of January 1, 2013, and do not purport to be indicative of statements of financial position or results of operations as of any future date or for any future period.

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	Rice Energy Inc.					Rice Energy Inc. Pro Forma	
	Year Ended December 31,			Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2011	2012	2013	2013	2014	2013	2014
(in thousands, except per share data)					(unaudited)		
Statement of operations data:							
Revenues:							
Natural gas, oil and NGL sales	$ 13,972	$ 26,743	$ 87,847	$ 60,219	$ 246,816	$ 178,524	$ 258,752
Firm transportation sales, net					11,851		11,851
Other revenue		457	757	580	2,878	757	2,878
Total revenues	13,972	27,200	88,604	60,799	261,545	179,281	273,481
Operating expenses:							
Lease operating	1,617	3,688	8,309	5,794	16,406	16,502	16,826
Gathering, compression and transportation	540	3,754	9,774	6,951	25,904	25,437	27,294
Production taxes and impact fees		1,382	1,629	1,029	2,624	2,887	2,693
Exploration	660	3,275	9,951	1,784	1,706	9,951	1,706
Incentive unit expense					101,695		101,695
Restricted unit expense	170		32,906	40,087		32,906	
Stock compensation expense					3,274		3,274
General and administrative	5,208	7,599	16,953	9,952	36,733	20,209	36,805
Depreciation, depletion and amortization	5,981	14,149	32,815	23,215	91,912	71,886	94,768
Write-down of abandoned leases	109	2,253			748	146	748
Acquisition expense					2,246		2,246
Loss (gain) from sale of interest in gas properties	(1,478)		4,230			4,230	
Total expenses	12,807	36,100	116,567	88,812	283,248	184,154	288,055
Operating income (loss)	1,165	(8,900)	(27,963)	(28,013)	(21,703)	(4,873)	(14,574)

Interest expense	(531)	(3,487)	(17,915)	(13,033)	(38,737)	(16,422)	(38,972)
Gain on purchase of Marcellus joint venture					203,579		
Other income (expense)	161	112	(357)	(408)	180	(1,153)	180
Gain (loss) on derivative instruments	574	(1,381)	6,891	16,698	5,357	10,238	(6,834)
Amortization of deferred financing costs	(2,675)	(7,220)	(5,230)	(4,760)	(1,728)	(5,394)	(1,743)
Loss on extinguishment of debt			(10,622)	(10,622)	(3,934)	(10,622)	(3,934)
Write-off of deferred financing costs					(6,896)		(6,896)
Equity in income (loss) of joint ventures	370	1,532	19,420	19,297	(2,656)	90	
Gain (loss) before income taxes	(936)	(19,344)	(35,776)	(20,841)	133,462	(28,136)	(72,773)
Income tax benefit (expense)					(18,787)	11,674	(11,024)
Net income (loss)	$ (936)	$ (19,344)	$ (35,776)	$ (20,841)	$ 114,675	$ (16,462)	$ (83,797)
Balance sheet data (at period end):							
Cash	$ 4,389	$ 8,547	$ 31,612		$ 131,978		
Total property and equipment, net	150,646	273,640	734,331				
Total assets	190,240	344,971	879,810		2,895,786		
Total debt	107,795	149,320	426,942		901,006		
Total stockholders capital	46,821	138,191	298,647		1,412,558		
Net cash provided by (used in):							
Operating activities	$ 5,131	$ (3,014)	$ 33,672	$ 22,491	$ 69,679		
Investing activities	(79,245)	(119,973)	(458,595)	(342,625)	(1,154,548)		
Financing activities	73,447	127,145	447,988	339,249	1,185,235		
Other financial data (unaudited):							
Loss per share basic						$ (0.13)	$ (0.65)
Loss per share diluted						$ (0.13)	$ (0.65)

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RATIOS OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratios of consolidated earnings to fixed charges for the periods presented:

	Year Ended December 31,(b)					Nine Months Ended September 30,
	2009	2010	2011	2012	2013	2014
Ratio of earnings to fixed charges(a)(c)	(11.51)x	(2.14)x	0.20x	(0.33)x	0.24x	4.29x

(a) For purposes of calculating the ratios of consolidated earnings to fixed charges, earnings consists of pre-tax income (loss) from continuing operations, (income) loss from equity investees, distributed income of equity investees and interest capitalized, plus fixed charges. Fixed charges consist of interest expense, including amortization of discounts, interest capitalized and deferred financing amortization.

(b) We would have needed to generate additional earnings of $24.6 million, $25.2 million, $6.9 million, $3.9 million and $7.2 million to achieve coverage of 1:1 for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively.

(c) We had no preferred stock outstanding for any period presented, and accordingly, the ratio of earnings to combined fixed charges and preferred stock dividends is the same as the ratio of earnings to fixed charges.

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

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

Overview

We are an independent natural gas and oil company engaged in the acquisition, exploration and development of natural gas and oil properties in the Appalachian Basin. We are focused on creating shareholder value by identifying and assembling a portfolio of low-risk assets with attractive economic profiles and leveraging our technical and managerial expertise to deliver industry-leading results. We strive to be an early entrant into the core of a shale play by identifying what we believe to be the core of the play and aggressively executing our acquisition strategy to establish a largely contiguous acreage position.

As of September 30, 2014, we held approximately 82,626 net acres in the southwestern core of the Marcellus Shale, primarily in Washington County and Greene County, 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 33,499 of our 53,816 net acres as of September 30, 2014 in the southeastern core of the Utica Shale, primarily in Belmont County, Ohio. We believe this area to be in the core of the Utica Shale based on 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.

Our average net daily production for the third quarter of 2014 is 247 Mcfe/d. We brought five operated net horizontal Marcellus wells and one operated net Utica well online during the third quarter of 2014.

Factors That Significantly Affect Our Financial Condition and Results of Operations

We derive substantially all of our revenues from the sale of natural gas that is produced from our interests in properties located in the Marcellus Shale. In the coming years, we expect to derive an increasing amount of our revenues from the sale of natural gas and, in a more limited amount, NGLs, that are produced from our interests in properties located in the Utica Shale. Our revenues, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Natural gas prices have historically been volatile and may fluctuate widely in the future due to a variety of factors, including but not limited to, prevailing economic conditions, supply and demand of hydrocarbons in the marketplace and geopolitical events such as wars or natural disasters. In the future, we will also be subject to fluctuations in oil and NGL prices. Sustained periods of low natural gas prices could materially and adversely affect our financial condition, our results of operations, the quantities of natural gas that we can economically produce and our ability to access capital.

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We use commodity derivative instruments, such as swaps, puts and collars, to manage and reduce price volatility and other market risks associated with our natural gas production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is accomplished through over-the-counter commodity derivative contracts with large financial institutions. We use a combination of fixed price natural gas swaps; zero cost collars and deferred puts for which we receive a fixed price (via either swap price, floor of collar or put price) for future production in exchange for a payment of the variable market price received at the time future production is sold. The prices contained in these derivative contracts are based on NYMEX Henry Hub prices. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. 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 differential, result from variances in regional natural gas prices compared to NYMEX Henry Hub prices as a result of regional supply and demand factors. During the fourth quarter of 2013 we began hedging basis differentials associated with our natural gas production. We elected not to designate our current portfolio of commodity derivative contracts as hedges for accounting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings.

Like other businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, a natural gas exploration and production company depletes part of its asset base with each unit of natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production in a cost effective manner. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost effective manner and to timely obtain drilling permits and regulatory approvals.

Our financial condition and results of operations, including the growth of production, cash flows and reserves, are driven by several factors, including:

- success in drilling new wells;
- natural gas prices;
- our access to, and the cost of accessing end markets for our production;
- the availability of attractive acquisition opportunities and our ability to execute them;
- the amount of capital we invest in the leasing and development of our properties;
- facility or equipment availability and unexpected downtime;

delays imposed by or resulting from compliance with regulatory requirements; and

the rate at which production volumes on our wells naturally decline.

Factors That Significantly Affect Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

Public Company Expenses. As a result of our IPO, we will incur direct, incremental general and administrative (G&A) expenses as a result of being a publicly traded company, including, but not limited to, costs associated with annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation.

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Corporate Reorganization and Marcellus JV Buy-In. The reorganization constituted a common control transaction and the discussion herein is contemplated as though this reorganization had occurred for the earliest period presented herein. As a result, the historical financial data may not give you an accurate indication of what our actual results would have been had the IPO and the transactions been completed at the beginning of the periods presented or of what our future results of operations are likely to be. For example, concurrently with the closing of our IPO, we acquired Alpha Holdings 50% interest in our Marcellus joint venture (the Marcellus JV Buy-In) and, as a result, for periods following January 29, 2014, the complete results of operations of our Marcellus joint venture are consolidated into our results of operations, as opposed to periods prior to January 29, 2014, for which the results of operations of our Marcellus joint venture are not consolidated, but rather reflected as equity in income (loss) from our 50% equity investment therein.

Income Taxes. We are a corporation under the Internal Revenue Code subject to federal income tax at a statutory rate of 35% of pretax earnings, and, as such, our future income taxes will be dependent upon our future taxable income. We did not report any income tax benefit or expense for periods prior to the consummation of our IPO because Rice Drilling B, our accounting predecessor, is a limited liability company that was not and currently is not subject to federal income tax. The reorganization of our business in connection with the closing of the IPO, such that it is now held by a corporation subject to federal income tax, required the recognition of a deferred tax asset or liability for the initial temporary differences at the time of the IPO. The resulting deferred tax liability of approximately $162.3 million was recorded in equity at the date of IPO. Because we anticipate that our deductions primarily related to intangible drilling costs (IDCs) will exceed 2014 earnings, we expect to generate significant net operating loss assets and deferred tax liabilities. No current tax expense was recorded as of the date of the IPO. For periods following completion of the IPO, we began recording a federal and state income tax liability associated with our status as a corporation.

Increased Drilling Activity. In the third quarter of 2014, we brought online five net horizontal Marcellus wells and one net horizontal Utica well and we expect to bring online 15 net horizontal Marcellus wells in the fourth quarter of 2014. From 2010 through June 2013, we ran a one-horizontal rig drilling program. In June 2013, we began operating a two-horizontal rig drilling program on our Marcellus Shale properties. In the first quarter of 2014, we operated a three-horizontal rig program, one of which operated in the Utica Shale. In the second and third quarters of 2014, we averaged two horizontal rigs. In the fourth quarter of 2014, we plan to average three horizontal rigs, with an average of one rig operating in the Utica Shale and two rigs operating in the Marcellus Shale. We expect our future drilling activity will become increasingly weighted towards the development of our Utica Shale acreage. The costs and production associated with the wells we expect to drill in the Utica Shale may differ substantially from those we have historically drilled in the Marcellus Shale.

Financing Arrangements. During the third quarter of 2014, our capital expenditures were financed with proceeds from our public offering (August 2014 Equity Offering) of 13,729,650 shares of our common stock at $27.30 per share, which included 7,500,000 shares sold by us and 6,229,650 shares sold by affiliates of Natural Gas Partners and Alpha Natural Resources, Senior Notes Offering (as defined below) and net cash provided by operating activities. In the future, we may incur additional indebtedness and issue additional equity to fund our acquisition and development activities. Please read Capital Resources and Liquidity Debt Agreements below for additional discussion of our financing arrangements.

On April 25, 2014, we issued $900.0 million (our Senior Notes Offering) of 6.25% senior notes due 2022 (the notes) in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act, which resulted in net proceeds to us of $882.7 million after deducting estimated expenses and initial purchasers discounts of approximately $17.3 million. We used $301.8 million of the net proceeds to repay and retire the Second Lien Term Loan Facility (defined below), with the remainder expected to be used to fund a portion of our capital expenditures program.

In April 2013, we entered into our $300.0 million Second Lien Term Loan Facility agreement (Second Lien Term Loan Facility). Net proceeds of our Second Lien Term Loan Facility of $288.3 million after offering fees and expenses were used to repay existing debt of $176.1 million and to partially fund the acquisition of

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approximately 33,499 net acres in the Utica Shale in Belmont County, Ohio. On April 25, 2014, the Company used a portion of the net proceeds from the Senior Notes Offering to repay and retire the Second Lien Term Loan Facility in the amount of $301.8 million.

In April 2013, we entered into our $500.0 million Senior Secured Revolving Credit Facility (Senior Secured Revolving Credit Facility). Concurrently with the closing of our IPO, on January 29, 2014, the Senior Secured Revolving Credit Facility was amended to, among other things, allow for the corporate reorganization that was completed simultaneously with the closing of the IPO, add us as a guarantor, increase the maximum commitment amount to $1.5 billion, increase the borrowing base to $350.0 million as a result of the Marcellus JV Buy-In and lower the interest rate owed on amounts borrowed under the Senior Secured Revolving Credit Facility. We used a portion of the net proceeds of the IPO to repay $115.0 million of borrowings under our Senior Secured Revolving Credit Facility and $75.4 million of borrowings outstanding under the revolving credit facility of our Marcellus joint venture. Concurrently with the Senior Notes Offering, we, as borrower, and Rice Drilling B, as predecessor borrower, amended the Senior Secured Revolving Credit Facility (Amended Credit Agreement) to, among other things, assign all of Rice Drilling B s rights and obligations under the Senior Secured Revolving Credit Facility to us, and we assumed all such rights and obligations as borrower under the Amended Credit Agreement. As of September 30, 2014, the borrowing base under our Senior Secured Revolving Credit Facility was $385.0 million with zero borrowings outstanding and $66.8 million of letters of credit outstanding. Availability under the borrowing base of our Senior Secured Revolving Credit Facility was $318.2 million as of September 30, 2014. In October 2014, we had a redetermination of the borrowing base under our Senior Secured Revolving Credit Facility which increased the borrowing base to $550.0 million.

Sources of Revenues

The substantial majority of our revenues are derived from the sale of natural gas and do not include the effects of derivatives. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. The following table provides detail of our operating revenues from the condensed consolidated statements of operations for the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Natural gas sales	$ 67,625	$ 23,526	$ 246,583	$ 60,219
Oil and natural gas liquids (NGL) sales	206		233	
Firm transportation sales, net	9,733		11,851	
Third party gathering revenue	1,563	24	2,878	61
Other revenue		139		519
Total operating revenues	$ 79,127	$ 23,689	$ 261,545	$ 60,799

NYMEX Henry Hub prompt month contract prices are widely-used benchmarks in the pricing of natural gas. The following table provides the high and low prices for NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated.

	Year Ended December 31,			Nine Months Ended September 30,	
	2013(1)	**2012(1)**	**2011(1)**	**2014(2)**	**2013(2)**
NYMEX Henry Hub High	$ 4.46	$ 3.90	$ 4.85	$ 7.94	$ 4.38
NYMEX Henry Hub Low	3.11	1.91	2.99	3.74	3.08
Differential to Average NYMEX Henry Hub	(0.01)	0.08	(0.12)	(0.62)	(0.04)

(1) Differential is calculated by comparing the average NYMEX Henry Hub price to our volume weighted average realized price per MMBtu, including our proportionate 50% share of the volumes sold by our Marcellus joint venture.
(2) Differential is calculated by comparing the average NYMEX Henry Hub price to our volume weighted average realized price per MMBtu before hedges, including 50% of the volumes sold by our Marcellus joint venture for the period from January 1, 2014 through January 28, 2014, contained within the three and nine months ended September 30, 2014 and for the three and nine months ended September 30, 2013. The remainder of the three months ended September 30, 2014 reflect (i) the completion of the corporate reorganization in connection with our IPO and (ii) the consummation of the Marcellus JV Buy-In, each on January 29, 2014.

We sell a substantial majority of our production to a single natural gas marketer, Sequent Energy Management, LP (Sequent). For the year ended December 31, 2013, sales to Sequent and Dominion Field Services (Dominion) represented 94% and 6% of our total sales, respectively. For the three and nine months ended September 30, 2014, sales to Sequent represented 83% and 87% of our total sales, respectively. If our natural gas marketers decided to stop purchasing natural gas from us, our revenues could decline and our operating results and financial condition could be harmed. Although a substantial portion of production is purchased by this 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.

Principal Components of our Cost Structure

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

Gathering, compression and transportation. These are costs incurred to bring natural gas to the market. Such costs include the costs to operate and maintain our low- and high-pressure gathering and compression systems as well as fees paid to third parties who operate low- and high-pressure gathering systems that transport our natural gas. We often enter into firm transportation contracts that secure takeaway capacity that includes minimum volume commitments, the cost for which is included in these expenses.

Production taxes and impact fees. Pennsylvania imposes an annual impact fee on each producing shale well for a period of 15 years. Ohio imposes a production tax which is based upon annual production. As we expand our operations into the Utica Shale in Ohio, the proportion of our production and producing wells from each state may change over time and, as a result, the proportion of our production taxes and impact fees will vary depending on our quantities produced from the Utica Shale, the number of producing shale wells in Pennsylvania, and the applicable production tax rates and impact fees then in effect.

Exploration expense. These include geological and geophysical costs, seismic costs, delay rental payments and costs incurred in the development of an unsuccessful exploratory well.

General and administrative expense. We expect that we will incur additional general and administrative expenses as a result of being a publicly-traded company. Please see Factors That Significantly Affect Comparability of Our Financial Condition and Results of Operations Public Company Expenses. In addition, certain of our employees hold incentive units in Rice Holdings and NGP Holdings that entitle the holder to a portion of distributions by Rice Holdings and NGP Holdings. While any such distributions did not and will not involve any cash payment by us, we recognized non-cash compensation expense of approximately \$101.7 million during the first nine months of 2014. As of September 30, 2014, the unrecognized compensation expense related to such incentive units is approximately \$77.3 million, which will be recognized over the remaining expected service period.

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

Write-down of abandoned leases. These write-downs include the cost of expensing certain lease acquisition costs associated with properties that we no longer expect to drill.

Interest expense. We have financed a portion of our working capital requirements and property acquisitions with borrowings under our revolving credit facility and term loan. As a result, we incur interest expense that is affected by the level of drilling, completion and acquisition activities, as well as fluctuations in interest rates and our financing decisions. We also incur interest expense on our convertible debentures. We will likely continue to incur significant interest expense as we continue to grow. To date, we have not entered into any interest rate hedging arrangements to mitigate the effects of interest rate changes. Additionally, we capitalized $8.0 million, $7.7 million and $5.4 million of interest expense for the years ended December 31, 2013, 2012 and 2011, respectively.

Derivative fair value loss (gain). We utilize commodity derivative contracts to reduce our exposure to fluctuations in the price of natural gas. We recognize gains and losses associated with our open commodity derivative contracts as commodity prices and the associated fair value of our commodity derivative contracts change. The commodity derivative contracts we have in place are not designated as hedges for accounting purposes. Consequently, these commodity derivative contracts are recorded at fair value at each balance sheet date with changes in fair value recognized as a gain or loss in our results of operations. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

Equity in income (loss) of joint ventures. This line item represents our proportionate share of earnings and losses from our equity method investments, including our Marcellus joint venture. Concurrently with the closing of our IPO, we acquired Alpha Holdings 50% interest in our Marcellus joint venture and, as a result, for periods following the completion of our IPO, the results of operations of our Marcellus joint venture will be included in our results of operations.

Income tax expense. Rice Drilling B, our accounting predecessor, is a limited liability company not subject to federal income taxes. Accordingly, no provision for federal income taxes has been provided for in our historical results of operations because taxable income was passed through to Rice Drilling B s members. Although we are a corporation under the Internal Revenue Code, subject to federal income taxes at a statutory rate of 35% of pretax earnings, we did not report any income tax benefit or expense until the consummation of our IPO. Based on our deductions primarily related to IDCs that are expected to exceed 2014 earnings, we expect to generate significant net operating loss deferred tax assets and deferred tax liabilities. We may report and pay state income or franchise taxes in periods where our IDC deductions do not exceed our taxable income or where state income or franchise taxes are determined on another basis.

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Historical Results of Operations

Three and Nine Months Ended September 30, 2014 Compared to Three and Nine Months Ended September 30, 2013

Below are some highlights of our financial and operating results for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013:

Our natural gas, oil and NGL sales were $67.8 million and $23.5 million in the three months ended September 30, 2014 and 2013, respectively and $246.8 million and $60.2 million in the nine months ended September 30, 2014 and 2013, respectively.

Our production volumes were 22,757 MMcfe and 6,618 MMcfe in the three months ended September 30, 2014 and 2013, respectively and 61,116 MMcfe and 15,728 MMcfe in the nine months ended September 30, 2014 and 2013, respectively.

Our firm transportation sales, net were $9.7 million and zero in the three months ended September 30, 2014 and 2013, respectively and $11.9 million and zero in the nine months ended September 30, 2014 and 2013, respectively.

Our per unit cash production costs were $0.67 per Mcfe and $0.86 per Mcfe in the three months ended September 30, 2014 and 2013, respectively and $0.73 per Mcfe and $0.88 per Mcfe in the nine months ended September 30, 2014 and 2013, respectively.

Our G&A expenses were $10.5 million and $4.2 million in the three months ended September 30, 2014 and 2013, respectively and $36.7 million and $10.0 million in the nine months ended September 30, 2014 and 2013, respectively.

The following tables set forth selected operating and financial data for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Change	2014	2013	Change
Natural gas sales (in thousands)	$ 67,625	$ 23,526	$ 44,099	$ 246,583	$ 60,219	$ 186,364
Oil and NGL sales (in thousands)	206		206	233		233
Natural gas, oil and NGL sales (in thousands)	$ 67,831	$ 23,526	$ 44,305	$ 246,816	$ 60,219	$ 186,597
	$ 9,733	$	$ 9,733	$ 11,851	$	$ 11,851

Firm transportation sales, net (in thousands)						
Natural gas production (MMcf)	22,740	6,618	16,122	61,096	15,728	45,368
Oil and NGL production (Bbls)	2,841		2,841	3,390		3,390
Total production (MMcfe)	22,757	6,618	16,139	61,116	15,728	45,388
Average natural gas prices before effects of hedges per Mcf	$ 2.97	$ 3.55	$ (0.58)	$ 4,04	$ 3.83	$ 0.21
Average realized natural gas prices after effects of hedges per Mcf(1)	2.98	3.67	(0.69)	3.70	3.76	(0.06)
Average oil and NGL prices per Bbl	72.48		72.48	68.82		68.82
Average costs per Mcfe						
Lease operating	$ 0.20	$ 0.27	$ (0.07)	$ 0.27	$ 0.37	$ (0.10)
Gathering, compression and transportation	0.42	0.51	(0.09)	0.42	0.44	(0.02)
Production taxes and impact fees	0.05	0.08	(0.03)	0.04	0.07	(0.03)
General and administrative	0.46	0.63	(0.17)	0.60	0.63	(0.03)
Depreciation, depletion and amortization	1.49	1.47	0.02	1.50	1.48	0.02

(1) The effect of hedges includes realized gains and losses on commodity derivative transactions.

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	Rice Energy Inc. Three Months Ended September 30, 2014	2013	Change	Rice Energy Inc. Nine Months Ended September 30, 2014	2013	Change
	(in thousands)					
Operating revenues:						
Natural gas, oil and NGL sales	$ 67,831	$ 23,526	$ 44,305	$ 246,816	$ 60,219	$ 186,597
Firm transportation sales, net	9,733		9,733	11,851		11,851
Other revenue	1,563	163	1,400	2,878	580	2,298
Total operating revenues	79,127	23,689	55,438	261,545	60,799	200,746
Operating expenses:						
Lease operating	4,553	1,777	2,776	16,406	5,794	10,612
Gathering, compression and transportation	9,597	3,365	6,232	25,904	6,951	18,953
Production taxes and impact fees	1,114	522	592	2,624	1,029	1,595
Exploration	747	338	409	1,706	1,784	(78)
Incentive unit expense	26,418		26,418	101,695		101,695
Restricted unit expense		32,381	(32,381)		40,087	(40,087)
Stock compensation expense	2,058		2,058	3,274		3,274
General and administrative	10,458	4,169	6,289	36,733	9,952	26,781
Depreciation, depletion and amortization	33,853	9,722	24,131	91,912	23,215	68,697
Acquisition expense	2,246		2,246	2,246		2,246
Amortization of intangible assets	408		408	748		748
Total operating expenses	91,452	52,274	39,178	283,248	88,812	194,436
Operating loss	(12,325)	(28,585)	16,260	(21,703)	(28,013)	6,310
Interest expense	(15,754)	(5,943)	(9,811)	(38,737)	(13,033)	(25,704)
Gain on purchase of Marcellus joint venture				203,579		203,579
Other income (loss)	(216)	38	(254)	180	(408)	588
Gain on derivative instruments	36,935	8,050	28,885	5,357	16,698)	(11,341)
Amortization of deferred financing costs	(707)	(958)	251	(1,728)	(4,760)	3,032
Loss on extinguishment of debt	(790)	(10,622)	9,832	(3,934)	(10,622)	6,688
Write-off of deferred financing costs				(6,896)		(6,896)
Equity in income (loss) of joint ventures		4,368	(4,368)	(2,656)	19,297	(21,953)
Income (loss) before income taxes	7,143	(33,652)	40,795	133,462	(20,841)	154,303
Income tax expense	(14,005)		(14,005)	(18,787)		(18,787)
Net income (loss)	$ (6,862)	$ (33,652)	$ 26,790	$ 114,675	$ (20,841)	$ 135,516
	132,269	88,000	44,269	125,412	77,895	47,517

Weighted average number of shares of common stock basic						
Weighted average number of shares of common stock diluted	132,269	88,000	44,269	125,678	77,895	47,783
Earnings per share basic	$ (0.05)	$ (0.38)	$ 0.33	$ 0.91	$ (0.27)	$ 1.18
Earnings per share diluted	$ (0.05)	$ (0.38)	$ 0.33	$ 0.91	$ (0.27)	$ 1.18

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013

Total operating revenues. The $44.3 million increase in natural gas, oil and NGL sales was mainly a result of an increase in production in the third quarter of 2014 compared to the third quarter of 2013. The increase in production was a result of increased drilling and completion activity, mainly in Washington County, Pennsylvania and Belmont County, Ohio and production from seven wells acquired in our acquisition of approximately 22,000 net acres and 12 developed Marcellus wells in western Greene County, Pennsylvania from Chesapeake Appalachia, L.L.C. and Statoil USA Onshore Properties Inc. for approximately $329 million on August 1, 2014 (the Greene

County Acquisition). Production volume increases were partially offset by approximately, 60 days of capacity restricted volumes from four pads as a result of longwall coal undermining. The impact of increased production volumes on operating revenues was partially offset by a decrease in realized prices in 2014 compared to 2013. In addition, operating revenues for the third quarter of 2014 were positively impacted by approximately $8.5 million in firm transportation sales, net, from the sale of unutilized capacity in September 2014 to a third party.

Lease operating expenses. The $2.8 million increase in lease operating expenses is attributable to an increase in the number of producing wells in 2014 as compared to the prior year. However, lease operating expenses per unit of production decreased due to improved efficiencies, primarily due to more producing wells per pad and lower fixed costs per well.

Gathering, compression and transportation. The $6.2 million increase in gathering, compression and transportation expenses is primarily attributable to increased firm transportation contracts in the third quarter of 2014 compared to the third quarter of 2013.

Incentive unit expense. The $26.4 million increase in incentive unit expense was due to $14.4 million of non-cash compensation expense recognized in relation to the incentive unit awards based on fair market value assumptions as of September 30, 2014. Additionally, NGP Holdings paid approximately $12.0 million to holders of certain NGP Holdings incentive units as a result of our August 2014 Equity Offering. See Item 1. Financial Statements Notes to Condensed Consolidated Financial Statements 8. Incentive Units for additional information.

G&A. The $6.3 million increase was primarily attributable to the additions of personnel to support our growth activities and related salary and employee benefits. At September 30, 2014, we had 250 employees as compared to 116 employees at September 30, 2013.

DD&A. The $24.1 million increase was a result of an increase in production and greater number of producing wells in the third quarter of 2014 compared to 2013. This is consistent with our expanded drilling program and increased production during the period.

Interest expense. The $9.8 million increase was a result of higher levels of average borrowings outstanding during the third quarter of 2014 in order to fund our capital programs.

Gain on derivative instruments. The $36.9 million gain on derivative contracts in the third quarter of 2014 was comprised of $36.8 million in unrealized gains and $0.1 million of cash receipts on the settlement of maturing contracts. In the third quarter of 2013, the $8.0 million gain was comprised of $7.3 million in unrealized gains and $0.8 million of cash receipts made on the settlement of maturing contracts. The gain in the third quarter of 2014 as compared to the gain in the same period in 2013 was attributable to a decrease in market prices.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Total operating revenues. The $186.6 million increase in natural gas, oil and NGL sales was mainly a result of an increase in production in the nine months ended 2014 compared to the nine months ended 2013. The increase in production was a result of increased drilling and completion activity, primarily in Washington County, Pennsylvania and Belmont County, Ohio, and production from seven wells acquired in our Greene County Acquisition on August 1, 2014. Production volume increases were partially offset by approximately 60 days of capacity restricted volumes from four pads as a result of longwall coal undermining. The impact of increased production volumes on operating revenues was partially offset by a decrease in realized prices in 2014 compared to 2013. In addition, operating revenues for the nine months ended September 30, 2014 were positively impacted by approximately $8.5 million in firm transportation sales, net, from the sale of unutilized capacity for the month of September 2014 to a third party.

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Lease operating expenses. The $10.6 million increase in lease operating expenses is attributable to an increase in the number of producing wells in 2014 as compared to the prior year. However, lease operating expenses per unit of production decreased due to improved efficiencies, primarily due to more producing wells per pad and lower fixed costs per well.

Gathering, compression and transportation. The $19.0 million increase in gathering, compression and transportation expenses is primarily attributable to increased firm transportation contracts in 2014 compared to 2013.

Incentive unit expense. The $101.7 million increase in incentive unit expense was due to approximately $81.9 million of non-cash compensation expense related to incentive units still outstanding which related to the service period from date of grant through September 30, 2014. In addition, the increase was due to approximately $12.0 million paid to holders of certain NGP Holdings incentive units by NGP Holdings as a result of our August 2014 Equity Offering, payment by NGP Holdings of approximately $4.4 million related to payments made at IPO due to the New Tier I payout multiple being achieved and the payment by Daniel J. Rice III of approximately $3.4 million related to his incentive unit burden. See Item 1. Financial Statements Notes to Condensed Consolidated Financial Statements 8. Incentive Units for additional information.

G&A. The $26.8 million increase was primarily attributable to the additions of personnel to support our growth activities and related salary and benefit expenses. At September 30, 2014, we had 250 employees as compared to 116 employees at September 30, 2013.

DD&A. The $68.7 million increase was a result of an increase in production and a greater number of producing wells in 2014 compared to 2013. This is consistent with our expanded drilling program and increased production during the period.

Interest expense. The $25.7 million increase was a result of higher levels of average borrowings outstanding during 2014 in order to fund our capital programs.

Gain on purchase of Marcellus joint venture. The $203.6 million gain on acquisition in the first quarter of 2014 was attributable to the Marcellus JV Buy-In transaction. As a result of our acquiring the remaining ownership in our Marcellus joint venture, we are required to remeasure our equity investment at fair value, which resulted in a non-recurring gain of approximately $203.6 million during the nine months ended September 30, 2014.

Gain on derivative instruments. The $5.4 million gain on derivative contracts in 2014 was comprised of $26.1 million in unrealized gains and $20.8 million of cash payments on the settlement of maturing contracts. In 2013, the $16.7 million gain was comprised of $17.8 million in unrealized gains and $1.1 million of cash payments made on settlement of maturing contracts. The gain in 2014 as compared to the gain in 2013 was attributable to an increase in market prices accompanied by a greater hedged volume of our natural gas production.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Below are some highlights of our financial and operating results for the year ended December 31, 2013:

- Our production volumes, including our 50% share of the production in our Marcellus joint venture, increased 164% to 34,438 MMcf in the year ended December 31, 2013 compared to 13,065 MMcf in the year ended December 31, 2012.

Our natural gas sales increased 229% to $87.8 million in the year ended December 31, 2013 compared to $26.7 million in the year ended December 31, 2012.

Our per unit cash production costs decreased 15% to $1.60 per Mcf in the year ended December 31, 2013 compared to $1.88 per Mcf in the year ended December 31, 2012. Cash production costs include amounts paid for Pennsylvania impact fees of $0.07 per Mcf and $0.16 per Mcf for the year ended December 31, 2013 and December 31, 2012, respectively. Pennsylvania began assessing an impact fee on wells spud in the first quarter of 2012 and retroactively assessed fees for wells spud prior to 2012. Of the $0.16 per Mcf incurred in the year ended December 31, 2012, approximately $0.07 per Mcf relates to charges assessed by the state of Pennsylvania for wells spud prior to 2012. The remaining $0.09 relates to wells spud in 2012.

Our general and administrative expenses increased 123% to $17.0 million in the year ended December 31, 2013 compared to $7.6 million for the year ended December 31, 2012.

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The following tables set forth selected operating and financial data for the year ended December 31, 2013 compared to the year ended December 31, 2012:

	Year Ended December 31, 2013	2012	Amount of Change
	(in thousands)		
Revenues:			
Natural gas sales	$ 87,847	$ 26,743	$ 61,104
Other revenue	757	457	300
Total revenues	88,604	27,200	61,404
Operating expenses:			
Lease operating	8,309	3,688	4,621
Gathering, compression and transportation	9,774	3,754	6,020
Production taxes and impact fees	1,629	1,382	247
Exploration	9,951	3,275	6,676
Restricted unit expense	32,906		32,906
General and administrative	16,953	7,599	9,354
Depreciation, depletion and amortization	32,815	14,149	18,666
Write-down of abandoned leases		2,253	(2,253)
Loss from sale of interest in gas properties	4,230		4,230
Total operating expenses	116,567	36,100	80,467
Operating loss	(27,963)	(8,900)	(19,063)
Other income (expense):			
Interest expense	(17,915)	(3,487)	(14,428)
Other income (expense)	(357)	112	(469)
Gain (loss) on derivative instruments	6,891	(1,381)	8,272
Amortization of deferred financing costs	(5,230)	(7,220)	1,990
Loss on extinguishment of debt	(10,622)		(10,622)
Equity in income of joint ventures	19,420	1,532	17,888
Total other expense	(7,813)	(10,444)	2,631
Net loss	$ (35,776)	$ (19,344)	$ (16,432)
Natural gas sales (in thousands):			
Rice Energy Inc.	$ 87,847	$ 26,743	$ 61,104
Marcellus joint venture(1)	45,339	13,142	32,197
Production data (MMcf):			
Rice Energy Inc.	22,995	8,769	14,226
Marcellus joint venture(1)	11,443	4,296	7,147
Average prices before effects of hedges per Mcf:			

Rice Energy Inc.	$	3.82	$	3.05	$	0.77
Marcellus joint venture		3.96		3.06		0.90
Average realized prices after effects of hedges per Mcf(2):						
Rice Energy Inc.	$	3.85	$	3.15	$	0.70
Marcellus joint venture		4.16		3.07		1.09
Average costs per Mcf:						
Rice Energy Inc.						
Lease operating	$	0.36	$	0.42	$	(0.06)
Gathering, compression and transportation		0.43		0.43		
General and administrative		0.74		0.87		(0.13)
Depletion, depreciation and amortization		1.43		1.61		(0.18)
Marcellus joint venture:						
Lease operating	$	0.36	$	0.39	$	(0.03)
Gathering, compression and transportation		0.68		0.78		(0.10)
General and administrative		0.14		0.24		(0.10)
Depletion, depreciation and amortization		1.09		1.10		(0.01)

(1) Amounts presented for our Marcellus joint venture give effect to our 50% equity investment therein during the periods presented.
(2) The effect of hedges includes realized gains and losses on commodity derivative transactions.

Natural gas sales revenues. The $61.1 million increase was a result of an increase in production of 14,226 MMcf in 2013 compared to the prior year. The increase in production was a result of increased drilling and completion activity in Washington County, Pennsylvania. In addition, average prices before the effect of hedges increased from $3.05 per Mcf in 2012 to $3.82 per Mcf in 2013.

Lease operating expenses. The $4.6 million increase in lease operating expenses is attributable to higher production during 2013. However, lease operating expenses per unit of production decreased due to having more wells in early stages of production in 2013 as compared to 2012.

Gathering, compression and transportation. The $6.0 million increase in gathering, compression and transportation expenses is primarily attributable to increased production. The cost per Mcf of these expenses increased during 2013 primarily as a result of increased utilization of firm transportation.

Restricted unit expense. The $32.9 million increase in restricted unit expense relates to an increase in the fair value of the units during 2013. For a description of the restricted units, please see Note 9 to the audited consolidated financial statements included herein. In connection with our IPO, the restricted units were exchanged for shares of our common stock. Accordingly, we will not recognize such restricted unit expense subsequent to the exchange.

G&A. The $9.4 million increase was primarily attributable to the additions of personnel to support our growth activities.

DD&A. The $18.7 million increase was a result of higher average capitalized costs in 2013 compared to the prior year. The increase in capitalized costs is consistent with our expanded drilling program and increased production during the period.

Write-down of abandoned leases. The $2.3 million write-down in 2012 was attributable to our abandonment of certain leases that are outside our core areas of drilling focus.

Exploration expense. The $6.7 million increase in 2013 was primarily the result of the $8.1 million write-off of costs associated with the abandonment of the Bigfoot 7H in the fourth quarter of 2013.

Loss from sale of interest in gas properties. The $4.2 million loss from sale of interest in gas properties was attributable to the sale of interests in noncore assets in Lycoming County, Pennsylvania.

Gain (loss) on derivative instruments. The $6.9 million gain on derivatives contracts in 2013 was comprised of $6.2 million in unrealized gains and $0.7 million of cash receipts received on settlement of maturing contracts. In 2012, the $1.4 million loss was comprised of $2.3 million in unrealized losses and $0.9 million of cash receipts received on settlement of maturing contracts. The gain in 2013 was due to a decrease in market prices after we executed significant derivative contracts.

Interest expense. The $14.4 million increase was a result of higher levels of average borrowings outstanding during 2013 in order to fund our drilling programs.

Loss on extinguishment of debt. The $10.6 million loss on extinguishment of debt in 2013 was attributable to our repurchasing $53.1 million of outstanding convertible debentures, resulting in a put premium of $10.6 million being paid in accordance with the terms thereof.

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Equity in income of joint ventures. The $17.9 million increase was primarily a result of operations at our Marcellus joint venture. Approximately $1.7 million of the increased income from our Marcellus joint venture was attributable to net realized gains associated with its hedging program. Substantially all of the remaining increase in income was due to higher revenues, attributable to increased production volumes resulting from the execution of our Marcellus joint venture s drilling program.

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

Below are some highlights of our financial and operating results for the year ended December 31, 2012:

- Our production volumes, including our 50% share of the production in our Marcellus joint venture, increased 219% to 13,065 MMcf in the year ended December 31, 2012 compared to 4,089 MMcf in the year ended December 31, 2011.

- Our natural gas sales increased 91% to $26.7 million in the year ended December 31, 2012 compared to $14.0 million in the year ended December 31, 2011.

- Our per unit cash production costs decreased 14% to $1.88 per Mcf in the year ended December 31, 2012 compared to $2.18 per Mcf in the year ended December 31, 2011. Cash production costs include amounts paid for Pennsylvania impact fees of $0.16 per Mcf for year ended December 31, 2012. Pennsylvania began assessing an impact fee in the first quarter of 2012 and retroactively assessed fees for wells spud prior to 2012. Of the $0.16 per Mcf incurred in the year ended December 31, 2012, approximately $0.07 per Mcf relates to charges assessed by the state of Pennsylvania for wells spud prior to 2012. The remaining $0.09 relates to wells spud in 2012.

- Our total operating expenses increased 180% to $43.3 million in the year ended December 31, 2012 compared to $15.5 million in the year ended December 31, 2011. This increase was generally in line with our increase in revenue resulting from the execution of our drilling program.

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The following table sets forth selected operating and financial data for the year ended December 31, 2012 compared to the year ended December 31, 2011:

	Year Ended December 31, 2012	2011	Amount of Change
	(in thousands)		
Revenues:			
Natural gas sales	$ 26,743	$ 13,972	$ 12,771
Other revenue	457		457
Total revenues	27,200	13,972	13,228
Operating expenses:			
Lease operating	3,688	1,617	2,071
Gathering, compression and transportation	3,754	540	3,214
Production taxes and impact fees	1,382		1,382
Exploration	3,275	660	2,615
Restricted unit expense		170	(170)
General and administrative	7,599	5,208	2,391
Depreciation, depletion and amortization	14,149	5,981	8,168
Write-down of abandoned leases	2,253	109	2,144
Gain from sale of interest in gas properties		(1,478)	1,478
Total operating expenses	36,100	12,807	23,293
Operating income (loss)	(8,900)	1,165	(10,065)
Other income (expense):			
Interest expense	(3,487)	(531)	(2,956)
Other income	112	161	(49)
Gain (loss) on derivative instruments	(1,381)	574	(1,955)
Amortization of deferred financing costs	(7,220)	(2,675)	(4,545)
Equity in income of joint ventures	1,532	370	1,162
Total other expenses	(10,444)	(2,101)	(8,343)
Net loss	$ (19,344)	$ (936)	$ (18,408)
Natural gas sales (in thousands):			
Rice Energy Inc.	$ 26,743	$ 13,972	$ 12,771
Marcellus joint venture(1)	13,142	2,872	10,270
Production data (MMcf):			
Rice Energy Inc.	8,769	3,392	5,377
Marcellus joint venture(1)	4,296	697	3,599
Average prices before effects of hedges per Mcf:			
Rice Energy Inc.	$ 3.05	$ 4.12	$ (1.07)

Marcellus joint venture		3.06		4.12		(1.06)
Average realized prices after effects of hedges per Mcf(2):						
Rice Energy Inc.	$	3.15	$	4.29	$	(1.14)
Marcellus joint venture		3.07		4.12		(1.05)
Average costs per Mcf:						
Rice Energy Inc.						
Lease operating	$	0.42	$	0.48	$	(0.06)
Gathering, compression and transportation		0.43		0.16		0.27
General and administrative		0.87		1.54		(0.67)
Depletion, depreciation and amortization		1.61		1.76		(0.15)
Marcellus joint venture:						
Lease operating	$	0.39	$	0.51	$	(0.12)
Gathering, compression and transportation		0.78		0.04		0.74
General and administrative		0.24		0.26		(0.02)
Depletion, depreciation and amortization		1.10		1.57		(0.47)

(1) Amounts presented for our Marcellus joint venture give effect to our 50% equity investment therein during the period presented.
(2) The effect of hedges includes realized gains and losses on commodity derivative transactions.

Natural gas sales revenues. The $12.8 million increase was a result of an increase in production of 5,377 MMcf in 2012 compared to the prior year, partially offset by a 26% decrease in average prices before the effect of hedges. The increase in production was a result of a significant acceleration of our drilling and completion program.

Lease operating expenses. The $2.1 million increase in lease operating expenses is generally consistent with the increase in production volumes in 2012 compared to 2011.

Gathering, compression and transportation. Of the $3.2 million increase, $2.4 million is attributable to our purchase of firm transportation to transport our produced natural gas to the markets where it is sold. The firm transportation commitment was made in anticipation of increasing production volumes, which resulted in increased utilization of this firm transportation throughout 2012 and into 2013. The remaining increase in gathering, compression and transportation is due to overall higher production volumes in 2012 compared to 2011.

G&A. The increase of $2.4 million was primarily attributable to the addition of personnel to support our growth activities.

DD&A. The increase of $8.2 million was a result of higher average capitalized costs in 2012 compared to 2011. The increase in capitalized costs is consistent with our expanded drilling program and increased production during the period.

Amortization of deferred financing costs. The increase of $4.5 million was a result of the amendment to our Marcellus joint venture s credit agreement (Wells Fargo Credit Facility) with Wells Fargo Bank, N.A. (Wells Fargo) during the 2012 period in order to fund our drilling programs.

Write-down of abandoned leases. The $2.3 million write-off in 2012 was attributable to our abandonment of certain leases that are outside our core areas of drilling focus.

Gain from sale of interest in gas properties. In 2011, we recognized a gain related to the sale of a 50% working interest in certain gas properties in the Marcellus Shale.

Gain (loss) on derivative instruments. The $1.4 million loss on derivatives contracts in 2012 was comprised of $2.3 million in unrealized losses and $0.9 million of cash payments received on settlement of maturing contracts. In 2011, the $0.6 million gain was represented by cash payments received on settlement of maturing contracts.

Interest expense. The increase of $3.0 million was primarily attributable to higher levels of average borrowings outstanding during the 2012 period in order to fund our drilling programs.

Equity in income of joint ventures. The increase of $1.2 million was primarily a result of an increase in operating income attributable to higher production volumes of our Marcellus joint venture.

Capital Resources and Liquidity

Our primary sources of liquidity have been the proceeds from our IPO, August 2014 Equity Offering, Senior Notes Offering, equity contributions from our sponsors, our Amended Credit Agreement and net proceeds from the sale of Rice Drilling B s convertible debentures. Our primary use of capital has been the acquisition and development of natural gas properties. As we pursue reserve and production growth, we monitor which capital resources, including equity and debt financings, are available to us to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. We also expect to fund a portion of these requirements with cash flow from operations as we continue to bring additional production online.

Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us. In 2014, excluding (i) $100.0 million paid with respect to the Marcellus JV Buy-In, (ii) approximately $111.4 million paid with respect to our acquisition of certain gas gathering assets in eastern Washington and Green Counties, Pennsylvania and (iii) approximately $329.5 million paid with respect to the Greene County Acquisition, we plan to invest $1,230.0 million in our operations, including $430.0 million for drilling and completion in the Marcellus Shale, $150.0 million for drilling and completion in the Utica Shale, $385.0 million for leasehold acquisitions and $265.0 million for midstream infrastructure development. Our capital budget excludes acquisitions, other than $385.0 million for leasehold acquisitions. This represents a 96% increase over our $629.0 million pro forma 2013 capital expenditures. Without giving pro forma effect to the Marcellus JV Buy-In, our 2013 capital budget was $578.0 million. We expect to fund the remainder of our 2014 capital expenditures with cash generated by operations, a portion of the net proceeds of our Senior Notes Offering, the net proceeds of our IPO and August 2014 Equity Offering and borrowings under our Senior Secured Revolving Credit Facility. A portion of our 2014 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 December 31, 2013 reserve report. The failure to achieve projected production and cash flows from operations from such wells could result in a reduction to our 2014 capital budget. Our 2014 capital budget may be further adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas prices decline to levels below our acceptable levels, or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe will have the highest expected rates of return and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in commodity prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside our control.

We believe that operating cash flows and available borrowings under our Senior Secured Revolving Credit Facility should be sufficient to meet our current cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies. However, to the extent that we consider market conditions favorable, we may access the capital markets to raise capital from time to time to fund acquisitions, pay down our Senior Secured Revolving Credit Facility and for general working capital purposes.

See Debt Agreements below for additional details on our outstanding borrowings and available liquidity under our various financing arrangements.

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $69.7 million for the nine months ended September 30, 2014, compared to $22.5 million of net cash provided by operating activities for the nine months ended September 30, 2013. The change in operating cash flow was primarily the result of higher production in 2014 at a higher realized gas price, along with net decreases in per unit production costs.

Net cash provided by operating activities was $33.7 million for the year ended December 31, 2013, compared to $3.0 million of net cash used in operating activities for the year ended December 31, 2012. The change in operating cash flow was primarily the result of a $2.2 million increase in net income before DD&A; $17.9 million of which was attributable to undistributed earnings from our Marcellus joint venture and changes in working capital.

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For the year ended 2012, net cash used in operating activities was $3.0 million compared to net cash provided by operating activities of $5.1 million for the year ended December 31, 2011. The decrease in cash flow from operations for the year ended December 31, 2012 compared to 2011 was primarily due to an approximate $4.7 million change in working capital items.

Cash Flow Used In Investing Activities

During the nine months ended September 30, 2014 cash flows used in investing activities increased to $1,154.5 million from $342.6 million for the nine months ended September 30, 2013. This was primarily related to increased capital expenditures for drilling, development and acquisition costs. The acquisitions of our Marcellus Shale joint venture, Momentum and Greene County resulted in a net cash outflow of $523.7 million.

During the years ended December 31, 2013 and 2012, cash flows used in investing activities were $458.6 million and $120.0 million, respectively, primarily related to our capital expenditures for drilling, development and acquisition costs. In addition, we made a $10.0 million investment in our Marcellus Shale joint venture during the year ended December 31, 2012.

During the years ended December 31, 2012 and 2011, cash flows used in investing activities were $120.0 million and $79.2 million, respectively, primarily related to our capital expenditures for drilling, development and acquisition costs, net of sales proceeds. Nearly all of our investments in unconsolidated joint ventures of $10.0 million and $15.2 million for the years ended December 31, 2012 and 2011 related to our Marcellus joint venture.

Cash Flow Provided By Financing Activities

Net cash provided by financing activities of $1,185.2 million during the nine months ended September 30, 2014 was primarily the result of the proceeds from our Senior Notes Offering, our IPO and August 2014 Equity Offering (net of offering costs) which was offset by repayments of debt. Net cash provided by financing activities of $339.2 million during the nine months ended September 30, 2013 was primarily related to borrowings under our Second Lien Term Loan facility.

Net cash provided by financing activities of $448.0 million during the year ended December 31, 2013 was primarily the result of debt borrowings net of repayments that are more fully described in Debt Agreements below. In addition, we received capital contributions from our stockholders of $196.0 million and $96.8 million during the years ended December 31, 2013 and 2012, respectively.

Net cash provided by financing activities of $127.1 million during the year ended December 31, 2012 was primarily attributable to capital contributions from our stockholders and net borrowings under debt agreements that are further described in Debt Agreements below. Net cash provided by financing activities of $73.4 million during the year ended December 31, 2011 was primarily the result of debt borrowings net of repayments.

Debt Agreements

6.25% Senior Notes Due 2022

On April 25, 2014, we offered $900.0 million in aggregate principal amounts of the notes due 2022 in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act, which resulted in net proceeds to us of $882.7 million after deducting estimated expenses and underwriting discounts and commissions of approximately $17.3 million. We used $301.8 million of the net proceeds to repay and retire the Second Lien Term

Loan Facility and expect to use the remainder to fund our capital expenditure plan. See Description of Notes section of this prospectus for a detailed description of the terms of the notes.

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Senior Secured Revolving Credit Facility

Concurrently with our Senior Notes Offering, we, as borrower, and Rice Drilling B, as predecessor borrower, entered into the Amended Credit Agreement to, among other things, assign all of the rights and obligations of Rice Drilling B as borrower under its Senior Secured Revolving Credit Facility to us. Furthermore, the Amended Credit Agreement (i) allowed for the Senior Notes Offering and (ii) provided that we did not incur an immediate reduction in the borrowing base under the Senior Secured Revolving Credit Facility as a result of the Senior Notes Offering. The Amended Credit Agreement also extended the maturity date of the Senior Secured Revolving Credit Facility from April 25, 2018 to January 29, 2019.

The Amended Credit Agreement is secured by liens on at least 80% of the proved oil and gas reserves of us and our subsidiaries (other than any subsidiary that is designated as an unrestricted subsidiary), as well as significant unproved acreage and substantially all of the personal property of us and such restricted subsidiaries, and the Amended Credit Agreement is guaranteed by such restricted subsidiaries. The Amended Credit Agreement contains restrictive covenants that limit the ability of us and our restricted subsidiaries to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make or declare dividends;
- hedge future production or interest rates;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The Amended Credit Agreement also requires us to maintain certain financial ratios, which are measured at the end of each calendar quarter:

- a current ratio, which is the ratio of consolidated current assets (including unused commitments under the Amended Credit Agreement and excluding non-cash derivative assets) to consolidated current liabilities (excluding current maturities under the Amended Credit Agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and

- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX (as such term is defined in the Amended Credit Agreement) based on the trailing twelve month period to consolidated interest expense, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of September 30, 2014.

Second Lien Term Loan Facility

On April 25, 2013, Rice Drilling B entered into a Second Lien Term Loan Facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders in an aggregate principal amount of $300.0 million. Rice Drilling B estimated the discount on issuance of this instrument based upon an estimate of market rates at the inception of the instrument and recorded a discount of $4.5 million. The discount was being amortized over the life of the note using an effective interest rate of 0.284% using the effective yield method. On April 25, 2014, we used a portion of the net proceeds from our Senior Notes Offering to repay and retire the Second Lien Term Loan Facility, in the amount of $301.8 million. The $301.8 million included the outstanding principal balance of $297.0 million, a prepayment premium in the amount of approximately $3.0 million, and accrued but unpaid interest of $1.8 million.

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Convertible Debentures

In June of 2011, Rice Drilling B sold $60.0 million of its 12% Senior Subordinated Convertible Debentures due 2014 (the Debentures) in a private placement to certain accredited investors as defined in Rule 501 of Regulation D. The Debentures accrued interest at 12% per year payable monthly in arrears by the 15th day of the month and had a scheduled maturity date of July 31, 2014 (Maturity Date). The Debentures were Rice Drilling B s unsecured senior obligations and ranked equally with all of Rice Drilling B s then-current and future senior unsecured indebtedness.

In connection with the IPO, the Debentures and warrants of Rice Drilling B were amended to become convertible or exercisable for shares of our common stock. On February 28, 2014, Rice Drilling B issued a redemption notice on the remaining Debentures, which set a redemption date of March 28, 2014. Prior to the redemption date, $6.6 million of the Debentures were converted into 570,945 shares of Rice Energy Inc. common stock. The remaining principal balance of $0.3 million that was not converted will be paid upon request from holders of the remaining Debentures. The premium of $0.1 million was recorded to expense in the nine months ended September 30, 2014. As of September 30, 2014, the remaining principal balance was $0.2 million.

Commodity Hedging Activities

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

To mitigate the potential negative impact on our cash flow caused by changes in oil and natural gas prices, we have entered into financial commodity derivative contracts in the form of swaps, zero cost collars, calls, puts and basis swaps to ensure that we receive minimum prices for a portion of our future oil and natural gas production when management believes that favorable future prices can be secured. We typically hedge the NYMEX Henry Hub price for natural gas. The Amended Credit Agreement adjusted our hedging limitation. In the prior Senior Secured Revolving Credit Facility agreement, we were permitted to hedge volumes based on a percentage of expected production from proved reserve volumes. We are now permitted to hedge the greater of (i) the percentage of internally forecasted production (Column A) and (ii) the percentage of proved reserve volumes (Column B) according to the table below.

Months next succeeding the time as of which compliance is measured	Column A	Column B
Months 1 through 12	75%	85%
Months 13 through 24	50%	85%
Months 25 through 36	40%	85%
Months 37 through 48	25%	65%
Months 49 through 60	15%	65%

Our hedging activities are intended to support natural gas prices at targeted levels and to manage our exposure to natural gas price fluctuations. The counterparty is required to make a payment to us for the difference between the floor price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the floor price. We are required to make a payment to the counterparty for the difference between the ceiling price and the settlement price if the ceiling price is below the settlement price. These contracts may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty and zero cost collars that set a floor and ceiling price for the hedged production. For a description of our commodity derivative contracts, please see Note 11 to the consolidated financial statements of Rice Energy Inc. as of and for the year ended December 31, 2013 included elsewhere in this this prospectus.

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have derivative instruments in place with six different counterparties. As of September 30, 2014, our contracts with Wells Fargo Bank N.A. accounted for 60% of the net fair market value of our derivative assets. We believe Wells Fargo Bank N.A. is an acceptable credit risk. We are not required to provide credit support or collateral to Wells Fargo Bank N.A. under current contracts, nor are they required to provide credit support or collateral to us. As of September 30, 2014 and December 31, 2013, we did not have any past due receivables from counterparties.

Contractual obligations. A summary of our contractual obligations as of December 31, 2013 is provided in the following table, which does not reflect our IPO, our Senior Notes Offering or the respective uses of proceeds therefrom.

	Payments due by period						
	For the Year Ended December 31,						
	2014	2015	2016	2017	2018	Thereafter	Total
	(in thousands)						
Revolving Credit Facility(1)	$	$	$	$	$ 115,000	$	$ 115,000
Term Loan Facility(1)	3,000	3,000	3,000	3,000	285,750		297,750
Convertible Debentures(2)	7,372						7,372
NPI Note	8,500						8,500
Drilling rig commitments(3)	11,732	9,707					21,439
Gathering and firm transportation	28,327	52,072	65,557	65,420	63,968	361,842	637,186
Asset retirement obligations(4)						11,725	11,725
Other	3,360	2,205	1,396	1,302	898	352	9,513
Total	$ 62,291	$ 66,984	$ 69,953	$ 69,722	$ 465,616	$ 373,919	$ 1,108,485

(1) Includes outstanding principal amounts at December 31, 2013. This table does not include future commitment fees, amortization of deferred financing costs, interest expense or other fees on these facilities because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) Includes accrued interest and put premium for each period through maturity. From July 31, 2013 through August 20, 2013, any holder of convertible debentures had the right to cause us to repurchase all or any portion of the convertible debentures it owned at 100% of the portion of the principal amount of the convertible debentures as to which the right was being exercised, plus a premium of 20%. During this period, we repurchased $53.1 million of outstanding convertible debentures and paid a put premium of $10.6 million in accordance with the terms of the convertible debentures.

(3)

As of December 31, 2013, we had two horizontal drilling rigs under contract. One of these contracts expires in 2014. A third rig, which we took delivery of in February 2014, expires in 2015. Any other rig performing work for us is doing so on a well-by-well basis and therefore can be released without penalty at the conclusion of drilling on the current well. These types of drilling obligations have not been included in the table above. The values in the table represent the gross amounts that we are committed to pay. However, we will record in our financials our proportionate share based on our working interest.

(4) Represents gross retirement costs with no discounting impact.

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Material Weakness in Internal Control over Financial Reporting

Prior to the completion of our IPO, we were a private company with limited accounting personnel to adequately execute our accounting processes and other supervisory resources with which to address our internal control over financial reporting. In addition, our Marcellus joint venture historically relied on our accounting personnel for its accounting processes. We and our Marcellus joint venture had not maintained effective control environments in that the design and execution of our controls had not consistently resulted in effective review and supervision by individuals with financial reporting oversight roles. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare the financial statements of us and our Marcellus joint venture. We concluded that these control deficiencies constituted a material weakness in our control environment and in the control environment of our Marcellus joint venture. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

In 2011, we and our Marcellus joint venture did not maintain effective controls to ensure proper close processes, formal account reconciliations and technical accounting matter resolution and documentation. In 2012, we and our Marcellus joint venture did not maintain effective controls to ensure proper staffing and supervisory review. For each of these periods, effective controls were not adequately designed or consistently operating to ensure that key computations were properly reviewed before the amounts were recorded in our accounting records. The above identified control deficiencies resulted in audit adjustments to our consolidated financial statements during 2011 and 2012.

To address these control deficiencies, we have implemented additional analysis and reconciliation procedures and increased the levels of review and approval. In addition, we have hired 24 additional accounting and financial reporting staff to complement our historical accounting staff of four individuals as of December 31, 2012. These hires were made to allow for additional preparation and review time during our monthly accounting close process. Additionally, we have begun taking steps to comprehensively document and analyze our system of internal control over financial reporting in preparation for our first management report on internal control over financial reporting required in connection with our annual report for the year ended December 31, 2014. Although remediation efforts are still in progress, we believe the implementation of these changes has substantially improved our control environment as evidenced by the timely filing of our Annual Report on Form 10-K for the year ended December 31, 2013 and a significant decrease in audit adjustments as compared to prior periods. None of these audit adjustments were deemed material.

Due to the recent implementation of these changes to our control environment, management will continue to evaluate the design and effectiveness of these control changes in connection with its ongoing evaluation, documentation, review, formalization and testing of our internal control environment over the remainder of 2014. We have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures as of September 30, 2014. Based upon the status of our review, we and our independent auditors have concluded that the material weakness had not been fully remediated as of September 30, 2014.

During the course of the review, we may identify additional control deficiencies, which could give rise to significant deficiencies and other material weaknesses in addition to the material weakness previously identified. Our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of

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contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. See Note 1 of the notes to the audited consolidated financial statements for an expanded discussion of our significant accounting policies and estimates made by management.

Incentive units

We recognize non-cash compensation expense for incentive units awarded to certain of our employees by NGP Holdings and Rice Holdings. In connection with our IPO and related corporate reorganization, the holders of incentive units in Rice Appalachia contributed a portion of their incentive units to Rice Holdings and NGP Holdings in return for substantially similar incentive units in such entities. This resulted in the incentive units being deemed to have been modified, and the performance conditions were considered to be probable of occurring. Therefore, their fair values were measured and compensation expense from the date of initial grant through September 30, 2014 has been recognized in the nine months ended September 30, 2014.

It is currently expected that the NGP Holdings incentive units will be satisfied in cash and the Rice Holdings incentive units will be satisfied in shares of our common stock held by Rice Holdings. As a result of these different manners of payment satisfaction, the incentive units are accounted for differently, with the NGP Holdings incentive units being accounted for as liability awards and the Rice Holdings incentive units being accounted for as equity awards. For the NGP Holdings incentive units, for the nine months ended September 30, 2014, the fair value was measured as of September 30, 2014. For future reporting periods, the fair value used to determine the applicable compensation expense will be re-measured at each reporting period. For the Rice Holdings incentive units, the fair value of the incentive units was measured as of January 29, 2014, the date of modification. This fair value will underlie compensation expense charges for future reporting periods.

Determination of the fair value of the awards requires judgments and estimates regarding, among other things, the appropriate methodologies to follow in valuing the incentive units and the related inputs required by those valuation methodologies. The fair values underlying the compensation expense for both types of incentive units were estimated using a Monte Carlo simulation. The Monte Carlo simulation projected the share price for our common stock using the expected volatility, the risk free rate and other variables. The service period, which began on the date of grant and continues through final distribution, has been estimated primarily based upon our assumptions regarding the timing and size of secondary offerings of shares of our common stock by NGP Holdings and/or other liquidity events.

Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions. Any change in inputs or number of inputs to this calculation could impact the valuation and thus the non-cash compensation expense recognized. See Note 8 to our Condensed Consolidated Financial Statements for the nine months ended September 30, 2014 included elsewhere in this prospectus for additional information. Non-cash compensation expenses related to the incentive units is included in incentive unit expense within the Condensed Consolidated Statement of Operations.

Income taxes

We are a corporation under the Internal Revenue Code subject to federal income tax at a statutory rate of 35% of pretax earnings and, as such, our future income taxes will be dependent upon our future taxable income. We did not report any income tax benefit or expense for periods prior to the consummation of our IPO because Rice Drilling B, our accounting predecessor, is a limited liability company that was not and currently is not subject to federal income tax. The reorganization of our business in connection with the closing of the IPO, such that it is now held by a corporation subject to federal income tax, required the recognition of a deferred tax asset or liability for the initial temporary differences at the time of the IPO. The resulting deferred tax liability of approximately $162.3 million was recorded in equity at the date of the completion of the IPO as it represents a transaction among shareholders. Additionally, we have presented pro forma EPS for the nine month period ending September 30, 2014 assuming a statutory rate as disclosed in the accompanying condensed consolidated statements of operations.

Based on management s analysis, the Company did not have any uncertain tax positions as of September 30, 2014 and December 31, 2013.

Income taxes are accounted for under the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which differences are expected to be recovered or settled pursuant to the provisions of ASC 740-Income Taxes. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

We will record a valuation allowance if it is deemed more likely than not that all or a portion of its deferred income tax assets will not be realized. In addition, income tax rules and regulations are subject to interpretation and the application of those rules and regulations require judgment by us and may be challenged by the taxation authorities. We follow ASC 740-10-25, which requires the use of a two-step approach for recognizing and measuring tax benefits taken or expected to be taken in a tax return and disclosures regarding uncertainties in income tax positions. Only tax positions that meet the more likely than not recognition threshold are recognized.

Business Combinations

For acquisitions of working interests that are accounted for as business combinations, the results of operations are included in the Consolidated Statement of Operations from the date of acquisition. Purchase prices are allocated to assets acquired based on their estimated fair values at the time of acquisition. Fair value is the price that would be received to sell an asset or would be paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value. The fair value of natural gas properties is determined using a risk-adjusted after-tax discounted cash flow analysis based upon significant inputs including: 1) gas prices, 2) projections of estimated quantities of natural gas reserves, including those classified as proved, probable and possible, 3) projections of future rates of production, 4) timing and amount of future development and operating costs, 5) projected reserve recovery factors, and 6) weighted average cost of capital.

Revenue Recognition

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable. Natural gas is sold by us under contract with our natural gas marketers. Pricing provisions are tied to the Platts Gas Daily market prices.

Investments in Joint Ventures

We account for our oilfield service company joint venture investment and for periods prior to the completion of the Marcellus JV Buy-In accounted for our Marcellus joint venture investment, under the equity method of accounting as we have significant influence, but not control, over the joint ventures.

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Under the equity method of accounting, investments are carried at cost, adjusted for our proportionate share of the undistributed earnings or losses and reduced for any distributions from the investment. We also evaluate our equity method investments for potential impairment whenever events or changes in circumstances indicate that there is an other-than-temporary decline in value of the investment. Such events may include sustained operating losses by the investee or long-term negative changes in the investee s industry. These indicators were not present, and as a result, we did not recognize any impairment charges related to our equity method investments for any of the periods presented in the consolidated financial statements.

Gas Properties

We use the successful efforts method of accounting for gas-producing activities. Costs to acquire mineral interests in gas properties and to drill and equip exploratory wells that result in proved reserves are capitalized. Costs to drill exploratory wells that do not identify proved reserves as well as geological and geophysical costs and costs of carrying and retaining unproved properties are expensed.

Unproved gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Capitalized costs of producing gas properties and support equipment directly related to such properties, after considering estimated residual salvage values, are depreciated and depleted by the units of production method. Support equipment and other property and equipment not directly related to gas properties are depreciated over their estimated useful lives.

Management s estimates of proved reserves are based on quantities of natural gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic conditions. External engineers prepare the annual reserve and economic evaluation of all properties on a well-by-well basis. Additionally, we adjust natural gas reserves for major well rework or abandonment during the year as needed. The process of estimating and evaluating natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering, and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates over time. Because estimates of reserves significantly affect our DD&A expense, a change in our estimated reserves could have a material effect on our net income or loss.

On the sale of an entire interest in an unproved property for cash, a gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained unless the proceeds received are in excess of the cost basis which would result in gain on sale.

Asset Retirement Obligations

We record the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. For gas properties, this is the period in which a gas well is acquired or drilled. Our retirement obligations relate to the abandonment of gas-producing facilities and include costs to reclaim drilling sites and dismantle and relocate or dispose of gathering systems, wells, and related structures. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining lives of those wells based on reserve estimates.

When a new liability is recorded, we capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. To the extent future revisions to assumptions impact the present value of the existing asset retirement obligation a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment information, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. The liability is accreted to its present value each period and the capitalized cost is depreciated over the units of production basis.

Equity Incentives

We have entered into certain compensation arrangements with employees and, in limited cases, consultants. These arrangements have resulted in certain of the awards contained within the arrangements being accounted for as equity awards whereas other awards do not have the characteristics of equity and accordingly are not accounted for as such. These compensation arrangements require us to estimate the fair value of such arrangements. Management established an estimated fair value for issued units based upon an income approach prior to December 31, 2013. At December 31, 2013, in connection with our IPO, a market approach was used. Certain of the compensation arrangements contain performance conditions that need to be achieved in order for vesting in the arrangements to occur. We routinely monitor these performance conditions in order to determine if compensation expense is required to be recorded in the consolidated financial statements.

Depletion

Capitalized amounts attributable to proved oil and gas properties are depleted by the unit-of-production method over proved reserves. Depletion of the costs of wells and related equipment and facilities, including capitalized asset retirement costs, is computed using proved developed reserves. The reserve base used to calculate DD&A for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves.

Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk and Hedges

For a discussion of how we use financial commodity derivative contracts to mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, see Management s Discussion and Analysis of Financial Condition and Results of Operations Commodity Hedging Activities.

Interest Rate Risks

As of September 30, 2014, we had zero borrowings and approximately $66.8 million in letters of credit outstanding under our Senior Secured Revolving Credit Facility. Concurrently with the closing of our IPO, we amended our Senior Secured Revolving Credit Facility to, among other things, increase the maximum commitment amount to $1.5 billion and lower the interest rate owed on amounts borrowed under the Senior Secured Revolving Credit Facility. After giving effect to the amendment, the borrowing base under our Senior Secured Revolving Credit Facility was increased to $350.0 million as a result of the Marcellus JV Buy-In. As of September 30, 2014, we had availability under our Senior Secured Revolving Credit Facility of approximately $318.2 million and the borrowing base was increased to $385.0 million. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 150 to 250 basis points following the closing of our IPO, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points following the closing of our IPO as a result of the Marcellus JV Buy-In, depending on the percentage of our borrowing base utilized. The interest rate did not change under the Amended Credit Agreement.

As of September 30, 2014, we did not have any derivatives in place to mitigate the effects of interest rate risk. We may implement an interest rate hedging strategy in the future.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through joint interest receivables ($82.2 million as of September 30, 2014) and the sale of our natural gas production ($52.3 million in receivables as of September 30, 2014), which we market to multiple natural gas marketing companies. 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 leases 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. 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.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP.

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BUSINESS

We are an independent natural gas and oil company engaged in the acquisition, exploration and development of natural gas and oil properties in the Appalachian Basin. We are focused on creating shareholder value by identifying and assembling a portfolio of low-risk assets with attractive economic profiles and leveraging our technical and managerial expertise to deliver industry-leading results. We strive to be an early entrant into the core of a shale play by identifying what we believe to be the core of the play and aggressively executing our acquisition strategy to establish a largely contiguous acreage position. We believe we were an early identifier of the core of both the Marcellus Shale in southwestern Pennsylvania and the Utica Shale in southeastern Ohio.

All of our current and planned development is located in what we believe to be the core of the Marcellus and Utica Shales. The Marcellus Shale is one of the most prolific unconventional resource plays in the United States, and we believe the Utica Shale, based on initial drilling results, is a premier North American shale play. Together, these resource plays offer what we believe to be among the highest rate of return wells in North America. As of September 30, 2014, we held approximately 82,626 net acres in the southwestern core of the Marcellus Shale, primarily in Washington County and Greene County, 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 33,499 of our 53,816 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 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.

Since completing our first horizontal well in the fourth quarter of 2010, our pro forma average net daily production has grown approximately 120 times to 241 MMcf/d for the second quarter of 2014. Substantially all of our production through the second quarter of 2014 has been dry gas attributable to our operations in the Marcellus Shale. Prior to the second quarter of 2013, we ran a two-rig drilling program focused on delineating and defining the boundaries of our Marcellus Shale acreage position. In the second quarter of 2013, we shifted our operational focus from exploration to development, commencing a four-rig drilling program consisting of two rigs specifically for drilling the tophole sections of our horizontal wells and two rigs specifically for drilling the curve and lateral sections of our horizontal wells. In the first quarter of 2014, we increased to a six-rig drilling program (consisting of three tophole rigs and three horizontal rigs). In the second quarter of 2014, we averaged three horizontal rigs. We expect to continue to operate a six-rig drilling program through the remainder of 2014. The following chart shows our pro forma average net daily production for each quarter since completing our first horizontal well in the Marcellus Shale.

As of June 30, 2014, we had drilled and completed 51 horizontal Marcellus wells with lateral lengths ranging from 2,444 feet to 9,648 feet and averaging 6,291 feet. Our estimated ultimate recoveries (EUR) from our 37 producing wells at December 31, 2013, as estimated by our independent reserve engineer, NSAI, and normalized for each 1,000 feet of horizontal lateral, range from 1.2 Bcf per 1,000 feet to 3.0 Bcf per 1,000 feet, with an average of 1.9 Bcf per 1,000 feet. Additionally, we have drilled and completed three Upper Devonian horizontal wells on our Marcellus Shale acreage. 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 substantially all of our Marcellus Shale acreage in Southwestern Pennsylvania is prospective for the slightly shallower Upper Devonian Shale.

For the Utica Shale, we applied the same shale analysis and acquisition strategy that we developed and employed in the Marcellus Shale to acquire our acreage. In June 2014 we completed our first Utica well, the Bigfoot 9H, which tested at a stabilized rate of 41.7 MMcf/d. Please see Recent Developments Utica Update. Our delineation operations are being conducted with a two-rig drilling program (one tophole rig and one horizontal rig). We intend to maintain this two-rig drilling program in the Utica Shale through 2014. In 2015, we intend to transition to a primarily development-focused strategy in the Utica Shale.

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As of December 31, 2013, our pro forma estimated proved reserves were 602 Bcf, all of which were in southwestern Pennsylvania, with 42% proved developed and 100% natural gas. In 2014, we plan to invest $1,230.0 million in our operations (excluding acquisitions) as follows:

- $430.0 million for drilling and completion in the Marcellus Shale;
- $150.0 million for drilling and completion in the Utica Shale;
- $385.0 million for leasehold acquisitions; and
- $265.0 million for midstream infrastructure development.

This represents a 96% increase over our $629.0 million pro forma 2013 capital expenditures. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity. The following table provides a summary of our net acreage, average working interest, producing wells and projected 2014 net wells online as of June 30, 2014:

	Net Acreage	Average Working Interest	Producing Wells Gross	Producing Wells Net	2014 Projected Net Wells Online
Marcellus Shale(1)	53,834	95%	51	47	34
Utica Shale	50,772	96%	1	1	5(2)
Upper Devonian Shale(3)			3	3	
Total(3)	104,606		55	51	39

(1) Excludes non-strategic properties consisting of 548 net acres in Fayette and Tioga Counties, Pennsylvania. Includes 1,338 net acres that were included as a leasehold payable on our balance sheet as of June 30, 2014.
(2) Includes wells to be drilled by Gulfport Energy Corporation. Please see Our Properties Utica Shale Development Agreement and Area of Mutual Interest Agreement.
(3) Approximately 39,020 gross (36,932 net) acres in the Marcellus Shale is also prospective for the Upper Devonian Shale. The Upper Devonian and the Marcellus Shale are stacked formations within the same geographic footprint.

Our Properties

The Appalachian Basin, which covers over 185,000 square miles in portions of Kentucky, Tennessee, Virginia, West Virginia, Ohio, Pennsylvania and New York, is considered a highly attractive energy resource producing region with a long history of oil, natural gas and coal production. More importantly, the Appalachian Basin is strategically located near the high energy demand markets of the northeast United States, which has historically resulted in higher realized sales prices due to the reduced transportation costs a purchaser must incur to transport commodities to end users. Over the past five years, the focus of many producers has shifted from the younger, shallower conventional sandstone and carbonate reservoirs to the older, deeper Marcellus Shale and the newly emerging Utica Shale plays, which has driven

Appalachian basin production growth.

Marcellus Shale

The Devonian-aged Marcellus Shale is an unconventional reservoir that produces natural gas, NGLs and oil and is the largest unconventional natural gas field in the U.S. The productive limits of the Marcellus Shale cover over 90,000 square miles within Pennsylvania, West Virginia, Ohio and New York. The Marcellus Shale is a black, organic-rich shale deposit generally productive at depths between 6,000 to 10,000 feet. Production from the brittle, natural gas-charged shale reservoir is best derived from hydraulically fractured horizontal wellbores that exceed 2,000 feet in lateral length and involve multi-stage fracture stimulations.

In addition, we believe substantially all of our acreage is prospective for the Upper Devonian Shale, which is a black, organic rich shale comprised of the Geneseo Shale, Middlesex Shale and Rhinestreet Shale and is at shallower depths than the Marcellus Shale formation. In Washington and Greene Counties, Pennsylvania, the

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Upper Devonian Shale and Marcellus Shale are separated by the Tully Limestone which is approximately 30 feet thick in this area. We have drilled and completed three wells in the Upper Devonian Shale and confirmed the presence of the Upper Devonian Shale formation in each of our Marcellus Shale wells drilled as of June 30, 2014.

We have experienced virtually no geologic complexity in our drilling activities through December 31, 2013, which has resulted in a fairly predictable band of expected recoveries per 1,000 feet of lateral length on our wells. We completed 9 gross (9 net) horizontal Marcellus Shale wells in 2012 and 22 gross (19.9 net) horizontal Marcellus Shale wells in 2013. As of June 30, 2014, we had a total of 51 gross (47.2 net) producing wells in the Marcellus Shale.

For the quarter ended June 30, 2014, we had average pro forma net daily production of 241 MMcf/d. As of June 30, 2014, we had four rigs operating in the Marcellus Shale (two tophole rigs and two horizontal rigs) and two rigs operating in the Utica Shale (one tophole rig and one horizontal rig).

The following table provides a summary of our current gross and net acreage by county in Pennsylvania as of June 30, 2014.

County	Gross Acres	Net Acres
Core Southwestern Pennsylvania:		
Washington	40,591	39,013
Greene	15,257	14,624
Allegheny	197	197
Total	56,045	53,834

(1) Our other acreage within the Marcellus Shale is located in Fayette and Tioga Counties, Pennsylvania.

In December 2013, we sold all of our Lycoming County acreage (100% non-operated) and related assets to a third party in exchange for $7.0 million. There was no production or net proved reserves attributable to the interests sold. We incurred a loss of $4.2 million in the fourth quarter of 2013 as a result of this transaction.

Utica Shale

The Ordovician-aged Utica Shale is an unconventional reservoir underlying the Marcellus Shale. The productive limits of the Utica Shale cover over 80,000 square miles within Ohio, Pennsylvania, West Virginia and New York. The Utica Shale is an organic-rich continuous black shale, with most production occurring at vertical depths between 7,000 to 10,000 feet. To date, the rich and dry gas windows of the southern Utica Shale play with BTUs ranging from 1,050 to 1,250 have yielded the strongest well results. We estimate that approximately 20% of our Utica acreage is in this rich gas window, with BTUs ranging from 1,100 to 1,200, and the remaining 80% is in the dry gas window. The richest and thickest concentration of organic-carbon content is present within the Point Pleasant Shale layer of the Lower Utica formation. The Point Pleasant Shale is our primary targeted development play of the Utica Shale.

As of June 30, 2014, we owned 50,772 net acres in the core of the Utica Shale and expect to add to our sizeable land position. The proximity of our Utica acreage position to our operations in the Marcellus Shale allows us to capitalize on operating and midstream synergies.

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The following table provides a summary of our current gross and net acreage by county in Ohio as of June 30, 2014.

County	Gross Acres(1)	Net Acres
Belmont	48,281	48,281
Guernsey	3,899	1,727
Harrison	764	764
Total	52,944	50,772

(1) Excludes Gulfport s acreage covered by our Development Agreement and AMI Agreement.

In October 2013, we commenced drilling our initial Utica well, the Bigfoot 7H, in Belmont County, Ohio. In December 2013, after drilling approximately 1,200 feet of the lateral section within the Point Pleasant formation, the well unexpectedly began flowing gas with higher than anticipated bottomhole pressures. We employed certain steps, including increasing our drilling mud weight, that successfully controlled the gas flow. However, certain uncased sections in the vertical portions of the wellbore were compromised by the higher mud weight, which ultimately inhibited our efforts to stabilize the gas flow and pressures. We elected to plug the Bigfoot 7H in late December 2013 and drilled a new horizontal well adjacent to the Bigfoot 7H with reconfigured mud and intermediate casing designs to better manage higher anticipated pressures and gas flows. We wrote off approximately $8.1 million of exploratory costs associated with the drilling of the Bigfoot 7H in the fourth quarter of 2013.

On June 2, 2014, we announced the production test results of our first operated Utica Shale well, the Bigfoot 9H. After five days of flowback, the Bigfoot 9H stabilized at a rate of 41.7 MMcf/d of gas on a 33/64 choke with flowing casing pressures of 5850 psi. Based upon a gas composition analysis, the heat content is 1086 Btu and therefore will not require processing. We own an approximate 93% working interest in the well, which has an effective lateral length of 6,957 feet and was completed with 40 frac stages. First production from the Bigfoot 9H well was delivered into sales in late June 2014. In addition, in June 2014, we drilled and cased our second and third Utica Shale wells, the Blue Thunder 10H and 12H. We are in the process of completing both of these wells, each with lateral lengths of approximately 9,000 feet.

We believe that the production test results obtained on the Bigfoot 9H indicate a highly permeable and porous Point Pleasant formation. However, these pressures may not be an indicator of the production amounts to be expected from future Utica wells. In addition, we may experience further difficulties drilling and completing Utica wells. Please read Risk Factors Risks Related to Our Business We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Development Agreement and Area of Mutual Interest Agreement

On October 14, 2013, we entered into a Development Agreement and AMI Agreement with 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 68.80% participating interest in the Northern Contract Area and an approximately 42.63% participating interest in 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. For example, upon development of a well:

- Assuming an aggregate 90% working interest is held by us and/or Gulfport in the Northern Contract Area, we and Gulfport will make cross conveyances to one another such that we hold an approximately 61.92% working interest (representing 68.80% of 90%) and Gulfport holds an approximately 28.08% (representing 31.20% of 90%) working interest in the drilling unit; and

- Assuming an aggregate 90% working interest is held by us and/or Gulfport in the Southern Contract Area, we and Gulfport will make cross conveyances to one another such that we hold an approximate 38.37% working interest (representing 42.63% of 90%) and Gulfport holds an approximate 51.63% (representing 57.37% of 90%) working interest in the drilling unit.

As a result of the Development Agreement, as of December 31, 2013, we are the operator of approximately 27,000 aggregate net acres in the Northern Contract Area, and Gulfport is the operator of approximately 23,000 aggregate net acres in the Southern Contract Area. In addition, 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.

Each quarter during the term of the Development Agreement, we and Gulfport will establish a work program and budget detailing the proposed exploration and development to be performed in the Northern and Southern Contract Areas, respectively, for the following year. The number of horizontal wells proposed to be drilled in each of the Northern Contract Area and Southern Contract Area is limited by the Development Agreement as follows: in 2014, between eight and 40 wells; in 2015, between eight and 50 wells; and thereafter, unlimited.

Pursuant to the AMI Agreement, each party has the right to participate at the level of its applicable participating interest in any acquisition by the other party of working interests or leases acquired within the AMIs. Unless a party elects not to participate therein upon notice by the other party, the subject working interest or lease will be governed by the Development Agreement.

The Utica Development Agreements have terms of ten years and are terminable upon 90 days notice by either party; provided that, with respect to interests included within a drilling unit, such interests shall remain subject to the applicable joint operating agreement and we and Gulfport shall remain operators of drilling units located in the Northern Contract Area and Southern Contract Area, respectively, following such termination.

Midstream Operations

Our exploration and development activities are supported by our operated natural gas low- and high-pressure gathering, compression and transportation assets, as well as by third-party arrangements. Unlike many producing basins in the United States, certain portions of the Appalachian Basin do not have sufficient midstream infrastructure to support the existing and expected increasing levels of production. Actively managing these midstream operations enhances our ability to obtain the necessary takeaway capacity for our production.

We maintain a strong commitment to developing the necessary midstream infrastructure to support our drilling schedule and production growth. We seek to accomplish this goal through a combination of internal asset developments and contractual relationships with third-party midstream service providers. We have invested in building low- and high-pressure gathering lines and water pipeline systems. We will continue to invest in our midstream infrastructure, as it allows us to optimize our gathering and takeaway capacity to support our expected-production growth, affords us more control over the direction and planning of our drilling schedule and has historically lowered our operating costs. In 2014, we estimate we will spend a total of approximately $265.0 million on midstream infrastructure development (excluding amounts paid in connection with our acquisition of certain gas gathering assets in eastern Washington and Greene Counties, Pennsylvania which was completed on April 17, 2014).

As of December 31, 2013, we owned and operated 27 miles of high-pressure gathering pipelines on our Marcellus Shale acreage in Washington County, Pennsylvania. Due to the high flow rates and flowing tubing pressures experienced with our Marcellus wells, none of our wells requires nor utilizes artificial lift or compression.

Our midstream infrastructure in Pennsylvania also includes 33 miles of high-density polyethylene pipelines connected to multiple freshwater impoundments for transporting water to our well completion operations. We commenced construction of this system in 2010 and first utilized the system during the completion of our second horizontal Marcellus well. Since then, we have continued to expand this system and, as of December 31, 2013, this system has been utilized for the completion on substantially all of our Marcellus wells. We will continue to expand this system as our well development progresses. This system delivers year-round water supply, lessens water handling costs and decreases water truck traffic on local roadways. The cost savings associated with sourcing our water through this system, when compared to wells completed with water sourced only by truck, is approximately $500,000 per horizontal well.

On February 12, 2014, we entered into a purchase and sale agreement with M3 to acquire certain gas gathering assets in eastern Washington and Greene Counties, Pennsylvania, for aggregate consideration of approximately $110.0 million in cash. Please see Note 16 to the Consolidated Financial Statements included herein.

Transportation and Takeaway Capacity

As of June 30, 2014, our average annual contractual firm transportation and firm sales obligations for 2014 (July through December), 2015 and 2016 were approximately 450,000 MMBtu/d, 810,000 MMBtu/d, and 920,000 MMBtu/d, respectively, which are in excess of our pro forma average daily gross operated production of approximately 380,000 MMBtu/d for June 2014. 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 deliver minimum daily volumes or pay fees for any deficiencies in deliveries. We continue to actively identify and evaluate additional takeaway capacity to facilitate production growth in our Appalachian Basin position.

Business Strategies

Our objective is to create shareholder value by identifying and assembling a portfolio of low-risk assets with attractive economic profiles and leveraging our technical and managerial expertise to deliver industry-leading results. We seek to achieve this objective by executing the following strategies:

Pursue High-Graded Core Shale Acreage as an Early Entrant. Our acreage acquisition strategy has been predicated on our belief that core acreage provides superior production, ultimate recoveries and returns on investment. We leverage our technical expertise and analyze third-party data to be an early entrant into the core of a shale play. We develop an internally generated geologic model and then study publicly available third-party data, including well results and drilling and completion reports, to confirm our geologic model and define the core acreage position of a play. Once we believe that we have identified the core location, we aggressively execute on our acquisition strategy to establish a largely contiguous acreage position. By virtue of this strategy, we eliminate the need for large exploration programs requiring significant time and capital, and instead pursue areas that have been substantially de-risked, or high-graded, by our competitors. We have applied the expertise and approach that we employed in the Marcellus Shale to the Utica Shale, and we believe we will be able to achieve similar results.

Target Contiguous Acreage Positions in Prolific Unconventional Resource Plays. We will seek to continue to expand on our success in targeting contiguous acreage positions within the core of the Marcellus and Utica Shales. We believe a concentrated acreage position requires fewer wells and inherently less capital to define the geologic properties across the play and allows us to optimize our wellbore economics. As of June 30, 2014, we had drilled and completed 51 horizontal Marcellus wells, several of which have tested the outer boundaries of our Marcellus acreage position. Additionally, as a result of optimizing our wellbore design with a limited number of wells, we believe our ability to transition from exploration drilling to development drilling in the Marcellus Shale was accomplished with less capital invested than our peers. We intend to replicate this strategy in the Utica Shale.

Aggressively Develop Leasehold Positions to Economically Grow Production, Cash Flow and Reserves. We intend to continue to aggressively drill and develop our portfolio of drilling locations with a goal of growing production, cash flow and reserves in an economically-efficient manner. In the first quarter of 2014, we increased to a six-rig drilling program (consisting of three tophole rigs and three horizontal rigs). In the second quarter of 2014, we averaged three horizontal rigs. We expect to continue to operate a six-rig drilling program through the remainder of 2014. In executing our development strategy, we intend to leverage our operational control and the expertise of our technical team to deliver attractive production and cash flow growth. As the operator of a substantial majority of our acreage in the Marcellus and Utica Shales, we are able to manage (i) the timing and level of our capital spending, (ii) our exploration and development drilling strategies and (iii) our operating costs. We will seek to optimize our wellbore economics through a meticulous focus on rig efficiency, wellbore accuracy and completion design and execution. We believe that the combination of our operational control and technical expertise will allow us to build on our track record of superior production, cash flow and reserve growth.

Maximize Pipeline Takeaway Capacity to Facilitate Production Growth. We maintain a strong commitment to construct, acquire and control the midstream infrastructure necessary to meet our production growth. We will also continue to enter into long-term firm transportation arrangements with third party midstream operators to ensure our access to market. We believe our commitment to midstream infrastructure allows us to commercialize our production more quickly and provides us with a competitive advantage in acquiring bolt-on acreage.

Competitive Strengths

We possess a number of competitive strengths that we believe will allow us to successfully execute our business strategies:

Large, Contiguous Positions Concentrated in the Core of the Marcellus and Utica Shales. We own extensive and contiguous acreage positions in the core of two of the premier North American shale plays. We believe we were an early identifier of both the Marcellus Shale core in southwestern Pennsylvania and the Utica Shale core, primarily in Belmont County, Ohio, which allowed us to acquire concentrated acreage positions. Our core position and contiguous acreage in the Marcellus Shale have allowed us to delineate our position as well as produce industry-leading well results, as our wells have some of the highest initial production rates and EURs in the Marcellus Shale. Through a consolidated approach, we are able to increase rig efficiency, turning wells into sales faster, and de-risk our acreage position more efficiently. Additionally, to service our concentrated acreage positions, we construct and acquire water and midstream infrastructure, which enable us to reduce reliance on third party operators, minimize costs and increase our returns. This has been a strength in the Marcellus Shale and we believe our position in the Utica Shale will allow us to achieve similar results.

Expertise in Unconventional Resource Plays and Technology. We have assembled a strong technical staff of shale petroleum engineers and shale geologists that have extensive experience in horizontal drilling, operating multi-rig development programs and using advanced drilling technology. We have been early adopters of new oilfield services and techniques for drilling (including rotary steerable tools) and completions (including reduced-length frac stages). In the Marcellus Shale as of June 30, 2014, we have completed 51 gross horizontal wells totaling approximately 320,000 lateral feet. We have realized improvements in our drilling efficiency over time and we are now drilling lateral sections

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approximately 50% longer in approximately half the time as it has taken us historically. Our average horizontal lateral drilled in 2011 was 4,733 feet and took 13.0 days to drill from kickoff to total depth. Our average horizontal lateral drilled in 2013 was 7,700 feet and took 5.8 days to drill from kickoff to total depth. Our operating proficiency has also led to increased wellbore accuracy, completion design efficiencies and has yielded top tier production results as reflected in the fact that out of approximately 550 producing horizontal Marcellus Shale wells in Washington County, Pennsylvania, we drilled and completed the top two and four of the top six wells in terms of cumulative production through June 30, 2013, as reported by Pennsylvania s oil and gas department. Further, we are able to enhance our wellbore economics through multi-well pad drilling (one to nine wells per rig move) and long laterals targeting 6,000 to 10,000 feet.

Successful Infill Leasing Program. We have increased our acreage position in the core of the Marcellus Shale through bolt-on leases in the same targeted area. This strategy has allowed us to acquire acreage that provides additional drilling locations and/or adds horizontal feet to future wells. By implementing this strategy, we have grown our Marcellus Shale acreage position from our initial acquisition of 642 net acres in 2009 to 53,834 net acres as of June 30, 2014. We have replicated this strategy successfully in the Utica Shale in Belmont County as well, leasing an additional 17,273 net acres as of June 30, 2014 since our initial acquisition of approximately 33,499 net acres in November 2012. We intend to continue to focus our near-term leasing program on Greene and Washington Counties in Pennsylvania and on Belmont County in Ohio, with the strategy of using bolt-on leases to acquire acreage that immediately increases our drilling locations and/or drillable horizontal feet.

Access to Committed Takeaway Capacity. Our gas gathering pipeline system is currently designed to handle up to approximately 2 Bcf/d in the aggregate and, as of June 30, 2014, has an operating capacity of approximately 1 Bcf/d in the aggregate. This system connects our producing wells to multiple interstate transmission and other third-party pipelines. We plan to continue to build out our Pennsylvania gathering system congruent with our future development plans. We plan to replicate our strategy of constructing and controlling our own midstream system in Ohio and expect to have our gathering system in Belmont County substantially complete by the second quarter of 2015. We believe our commitment to constructing and controlling midstream assets allows us to efficiently bring wells online, mitigates the risk of unplanned shut-ins and creates pricing and transportation optionality by connecting to multiple interstate pipelines. To further ensure the deliverability of our Utica Shale production, we have entered into a precedent agreement for 175,000 dth/d firm transportation on the Rockies Express Pipeline beginning in June 2015 for a term of 20 years, which will provide us with greater access to Gulf Coast and Midwest markets. With this capacity, our firm transportation and firm sales portfolio will cover approximately 810,000 MMBtu/d in 2015 and 920,000 MMBtu/d in 2016. By securing firm transportation and firm sales contracts, we are better able to accommodate our growing production and manage basis differentials.

Significant Liquidity and Active Hedging Program. As of June 30, 2014, we had cash on hand of approximately $471.5 million, of which we used approximately $329 million to fund the purchase price of our recently completed Greene County Acquisition described under Recent Developments, and as of August 1, 2014, we had availability under our revolving credit facility of approximately $313.4 million. We believe this liquidity, along with our cash flow from operations and the proceeds of this offering, is sufficient to execute our current capital program. Additionally, our hedging program mitigates commodity price volatility and protects our future cash flows. We review our hedge position on an ongoing basis, taking into account our current and forecasted production volumes and commodity prices. As of August 11, 2014, we had entered into hedging contracts covering approximately 41 Bcf (224 MMcf/d) of natural gas production for June 2014 through December 2014 at a weighted average index floor price of $4.06 per MMBtu. Furthermore, as of August 11, 2014, we had entered into hedging contracts covering approximately 84 Bcf (231 MMcf/d) of natural gas production for 2015 at a weighted average index floor price of $4.04 per MMBtu.

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Proven and Stockholder-Aligned Management Team. Our management team possesses extensive oil and natural gas acquisition, exploration and development expertise in shale plays. For a discussion of our management s experience, please read Management. Our Chief Executive Officer, Chief Operating Officer, Vice President of Exploration & Geology and Vice President of Drilling have worked for us since we drilled our first horizontal Marcellus well. Our management team includes certain members of the Rice family who, along with other members of the management team, are also highly aligned with stockholders through a 31.3% economic interest in us after giving effect to this offering. In addition, our management team has a significant indirect economic interest in us through their ownership of incentive units in the form of interests in Rice Holdings and NGP Holdings. The value of these incentive units may increase over time, without diluting public investors, if our stock price appreciates in the future. For additional information regarding our incentive units, please read Executive Compensation Narrative Description to the Summary Compensation Table for the 2013 Fiscal Year Long-Term Incentive Compensation. We believe that our management team s direct and indirect ownership interest in us will provide significant incentives to grow the value of our business.

Initial Public Offering, Corporate Reorganization and Related Transactions

Initial Public Offering

On January 29, 2014, we completed our initial public offering (IPO) of 50,000,000 shares of our $0.01 par value common stock, which included 30,000,000 shares sold by us, 14,000,000 shares sold by NGP Holdings, the selling stockholder in our IPO and 6,000,000 shares subject to an option granted to the underwriters by the selling stockholder.

The net proceeds of our IPO, based on the public offering price of $21.00 per share, were approximately $993.5 million, which resulted in net proceeds to us of $593.6 million after deducting expenses and underwriting discounts and commissions of approximately $36.4 million and net proceeds to the selling stockholder of approximately $399.0 million after deducting underwriting discounts of approximately $21.0 million. We did not receive any proceeds from the sale of the shares by the selling stockholder. A portion of the net proceeds from our IPO were used to repay all outstanding borrowings under the revolving credit facility of our Marcellus joint venture, to make a $100.0 million payment to Alpha Holdings in partial consideration for the Marcellus JV Buy-In and to repay all outstanding borrowings under our revolving credit facility. The remainder of the net proceeds from our IPO are being used to fund a portion of our capital expenditure plan.

Corporate Reorganization

A corporate reorganization occurred concurrently with the completion of our IPO on January 29, 2014. As a part of this corporate reorganization, we acquired all of the outstanding membership interests in Rice Appalachia in exchange for shares of our common stock. Our business continues to be conducted through Rice Drilling B, as a wholly owned subsidiary. As of January 29, 2014, upon (a) the completion of the IPO, (b) the issuance of (i) 43,452,550 shares of common stock to NGP Holdings, (ii) 20,300,923 shares of common stock to Rice Holdings, (iii) 2,356,844 shares of common stock to Daniel J. Rice III, (iv) 20,000,000 shares of common stock to Rice Partners, (v) 160,831 shares of common stock to the persons holding incentive units representing interests in Rice Appalachia and (vi) 1,728,852 shares of common stock to the members of Rice Drilling B (other than Rice Appalachia), each of which were issued by us in connection with the closing of the IPO, and (c) the issuance of 9,523,810 shares of common stock to Alpha Holdings in connection with the completion of the Marcellus JV Buy-In described below under Marcellus JV Buy-In, we had 127,523,810 shares of common stock outstanding.

Marcellus JV Buy-In

On January 29, 2014, in connection with the closing of the IPO and pursuant to the Transaction Agreement between us and Alpha Holdings dated as of December 6, 2013 (the Transaction Agreement), we completed our

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acquisition of Alpha Holdings 50% interest in our Marcellus joint venture in exchange for total consideration of $322 million, consisting of $100 million of cash and our issuance to Alpha Holdings of 9,523,810 shares of our common stock.

Our Operations

Reserve Data

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

Reserves Presentation

Our estimated proved reserves and PV-10 as of December 31, 2013 and 2012 are based on evaluations prepared by our independent reserve engineers, NSAI. Copies of the summary reports of NSAI with respect to our reserves as of December 31, 2013 are filed as exhibits to this prospectus. See Preparation of Reserve Estimates for definitions of proved reserves and the technologies and economic data used in their estimation.

The following table summarizes our historical and pro forma estimated proved reserves and related PV-10 at December 31, 2013 and 2012.

	Natural Gas Estimated Net Reserves (Bcf)(1)					
	As of December 31, 2013			As of December 31, 2012		
	Rice Energy Inc. Pro Forma	Rice Energy Inc.	Marcellus Joint Venture(2)	Rice Energy Inc. Pro Forma	Rice Energy Inc.	Marcellus Joint Venture(2)
Estimated Proved Reserves:						
Total proved reserves	602	382	110	561	304	128
Total proved developed reserves	250	144	53	131	61	35
Total proved developed producing reserves	177	91	43	101	57	22
Total proved developed non-producing reserves	73	53	10	30	4	13
Total proved undeveloped reserves	352	238	57	430	243	93
Percent proved developed	42%	38%	48%	23%	20%	27%
PV-10 of proved reserves (in millions)(3)	$ 709	$ 417	$ 146	$ 245	$ 102	$ 71

(1) Our historical and pro forma estimated proved reserves, PV-10 and standardized measure were determined using a 12-month average price for natural gas. The prices used in our reserve reports yield weighted average wellhead prices, which are based on index prices and adjusted for energy content, transportation fees and regional price differentials. The index prices and the equivalent wellhead prices are shown in the table below.

	Index Prices Natural Gas (per MMBtu)			Weighted Average Wellhead Prices Natural Gas (per Mcf)		
	Rice Energy Inc. Pro Forma	Rice Energy Inc.	Marcellus Joint Venture	Rice Energy Inc. Pro Forma	Rice Energy Inc.	Marcellus Joint Venture
December 31, 2013	3.67	3.67	3.67	3.90	3.91	3.90
December 31, 2012	2.76	2.76	2.76	2.85	2.86	2.84

(2) Amounts presented for our Marcellus joint venture give effect to our 50% equity investment in our Marcellus joint venture.

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(3) PV-10 is a non-GAAP financial measure and generally differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, the respective historical PV-10s and standardized measures of us and our Marcellus joint venture are equivalent because as of December 31, 2013 and 2012, we and our Marcellus joint venture were not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our respective equity holders. However, in connection with the closing of our IPO, as a result of our corporate reorganization, we became subject to federal income tax and, as such, our future income taxes will be dependent upon our future taxable income. We estimate that our pro forma standardized measure, our historical standardized measure and the historical standardized measure for our Marcellus joint venture as of December 31, 2013, would have been approximately $444 million, $269 million and $175 million, respectively, as adjusted to give effect to the present value of approximately $265 million, $148 million and $117 million, respectively, of future income taxes as a result of our being treated as a corporation for federal income tax purposes. We estimate that our pro forma standardized measure, our historical standardized measure and the historical standardized measure for our Marcellus joint venture as of December 31, 2012, would have been approximately $163 million, $67 million and $96 million, respectively, as adjusted to give effect to the present value of approximately $84 million, $37 million and $47 million, respectively, of future income taxes as a result of our being treated as a corporation for federal income tax purposes. Neither PV-10 nor standardized measure represents an estimate of the fair market value of our natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in the estimated historical and pro forma proved undeveloped reserves of us and our Marcellus joint venture during 2013 and 2012 (in MMcf):

	Rice Energy Inc. Pro Forma	**Rice Energy Inc.**	**Marcellus joint venture(1)**
Proved undeveloped reserves, December 31, 2011	294,857	207,599	43,629
Conversions into proved developed reserves	(33,908)	(15,120)	(9,394)
Extensions	330,851	164,561	83,145
Price revisions	(162,543)	(113,993)	(24,275)
Proved undeveloped reserves, December 31, 2012	429,257	243,047	93,105
Conversions into proved developed reserves	(156,136)	(79,266)	(38,435)
Extensions	105,366	65,744	19,811
Price revisions	(25,510)	8,826	(17,168)
Proved undeveloped reserves, December 31, 2013	352,977	238,351	57,313

(1) Amounts presented for our Marcellus joint venture give effect to our 50% equity investment in our Marcellus joint venture.

During 2013, on a pro forma basis, extensions, discoveries, and other additions of 105,366 MMcf proved undeveloped reserves were added through the drillbit in the Marcellus Shale. The negative revision was primarily due to four Marcellus joint venture wells being removed from our current development plan. During 2012, on a pro forma basis, extensions, discoveries, and other additions of 330,851 MMcf proved undeveloped reserves were added through the drillbit in the Marcellus Shale. Downward price revisions resulted in a reduction of proved undeveloped reserves by 162,543 MMcf.

During 2013, on a pro forma basis, we incurred costs of approximately $156.0 million to convert 156,136 MMcf of proved undeveloped reserves to proved developed reserves. During 2012, on a pro forma basis, we incurred costs of approximately $36.0 million to convert 33,908 MMcf of proved undeveloped reserves to proved developed reserves. Estimated future development costs relating to the development of our proved undeveloped reserves as of December 31, 2013 on a pro forma basis are approximately $313.0 million over the next five years, which we expect to finance through proceeds from our IPO, cash flow from operations, borrowings under our revolving credit facility and other sources of capital financing. Our drilling programs are focused on proving our undeveloped leasehold acreage through delineation drilling. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also focus on drilling our proved undeveloped reserves. Based on our reserve reports as of December 31, 2013, we had 44 gross (39 net) pro forma locations in the Marcellus Shale associated with proved undeveloped reserves and 13 gross (12 net) locations in the Marcellus Shale associated with proved developed not producing reserves. All of our proved undeveloped reserves are expected to be developed over the next five years. See Risk Factors Risks Related to Our Business The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

Preparation of Reserve Estimates

Our pro forma reserve estimates as of December 31, 2013 and 2012 included in this prospectus were based on evaluations prepared by the independent petroleum engineering firm of NSAI in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources.

Proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term reasonable certainty implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. The technical and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, well-test data, production data (including flow rates), well data (including lateral lengths), historical price and cost information, and property ownership interests. Our independent reserve engineers use this technical data, together with standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis and analogy. The proved developed reserves and EURs per well are estimated using performance analysis and volumetric analysis. The estimates of the proved developed reserves and EURs for each developed well are used to estimate the proved undeveloped reserves for each proved undeveloped location (utilizing type curves, statistical analysis, and analogy). Proved undeveloped locations that are more than one offset from a proved developed well utilized reliable technologies to confirm reasonable certainty. The reliable technologies that were utilized in estimating these reserves include log data, performance data, log cross sections, seismic data, core data, and statistical analysis.

Internal Controls

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to NSAI in their reserves estimation process. Ryan I. Kanto, our Vice President of Operations, is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has substantial industry experience with positions of increasing responsibility in engineering and evaluations. Throughout each fiscal year, our technical team meets with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the reserve report is reviewed by our senior management with representatives of our independent reserve engineers and internal technical staff.

Qualifications of Responsible Technical Persons

Ryan I. Kanto joined Rice Energy in June 2011 and serves as our Vice President of Operations. Prior to Rice Energy, Mr. Kanto worked at EnCana Oil & Gas (USA) Inc. from June 2007 to May 2011. During this time he served as a facilities engineer in the Deep Bossier from June 2007 to January 2008, a reservoir engineer in the Barnett Shale until February 2009, and completion engineer in the Haynesville Shale until his departure. Mr. Kanto has bachelors degrees in Chemical Engineering and Engineering Management from the University of Arizona and has significant experience in unconventional shale gas plays.

Our proved reserve estimates shown herein at December 31, 2013 and 2012 and the proved reserve estimates shown herein for our Marcellus joint venture have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under the Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letters, each of which is filed as an exhibit to this registration statement, was Richard B. Talley, Jr., Vice President, Team Leader, and a consulting petroleum engineer. Mr. Talley is a Registered Professional Engineer in the State of Texas (License No. 102425). Mr. Talley joined NSAI in 2004 after serving as a Senior Engineer at ExxonMobil Production Company. Mr. Talley s areas of specific expertise include probabilistic assessment of exploration prospects and new discoveries, estimation of oil and gas reserves, and workovers and completions. Mr. Talley received an MBA degree from Tulane University in 2001 and a BS degree in Mechanical Engineering from University of Oklahoma in 1998. Mr. Talley meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Production, Revenues and Price History

Natural gas, NGLs, and oil are commodities; therefore, the price that we receive for our production is largely a function of market supply and demand. While demand for natural gas in the United States has increased dramatically since 2000, natural gas and NGL supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have been used to find and recover large amounts of oil and natural gas from various shale formations throughout the United States. Demand is impacted by general economic conditions, weather and other seasonal conditions. Over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas reserves that may be economically produced and our ability to access capital markets. See Risk Factors Risks Related to Our Business Natural gas, 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.

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The following table sets forth information regarding production, revenues and realized prices and production costs on a historical basis for the years ended December 31, 2013, 2012 and 2011, for us and our Marcellus joint venture on a standalone basis and on a pro forma basis for the year ended December 31, 2013. Amounts shown for our Marcellus joint venture give effect to the 50% equity investment we held therein as of December 31, 2013. For additional information on price calculations, see information set forth in Management s Discussion and Analysis of Financial Condition and Results of Operations.

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Natural gas sales (in thousands):			
Pro Forma Rice Energy Inc.	$ 178,525		
Rice Energy Inc.	87,847	$ 26,743	$ 13,972
Marcellus joint venture	45,339	13,142	2,872
Production data (MMcf):			
Pro Forma Rice Energy Inc.	45,881		
Rice Energy Inc.	22,995	8,769	3,392
Marcellus joint venture	11,443	4,296	697
Average prices before effects of hedges per Mcf:			
Pro Forma Rice Energy Inc.	$ 3.89		
Rice Energy Inc.	3.82	$ 3.05	$ 4.12
Marcellus joint venture	3.96	3.06	4.12
Average realized prices after effects of hedges per Mcf(1):			
Pro Forma Rice Energy Inc.	$ 4.01		
Rice Energy Inc.	3.85	$ 3.15	$ 4.29
Marcellus joint venture	4.16	3.07	4.12
Average costs per Mcf(2):			
Pro Forma Rice Energy Inc.:			
Lease operating	$ 0.36		
Gathering, compression and transportation	0.55		
General and administrative	0.44		
Depletion, depreciation and amortization	1.57		
Rice Energy Inc.:			
Lease operating	$ 0.36	$ 0.42	$ 0.48