Memorial Resource Development Corp.
Form S-4
April 17, 2015
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As filed with the Securities and Exchange Commission on April 17, 2015

Registration No. 333-

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM S-4

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Memorial Resource Development Corp.

(and the subsidiaries identified below in the Table of Subsidiary Guarantor Registrants)

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**46-4710769**
(State or other jurisdiction of	**(Primary Standard Industrial**	**(IRS Employer**

incorporation or organization)	Classification Code Number)	Identification Number)

500 Dallas Street, Suite 1800

Houston, Texas 77002

(713) 588-8300

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Kyle N. Roane

Senior Vice President, General Counsel and Corporate Secretary

500 Dallas Street, Suite 1800

Houston, Texas 77002

Telephone: (713) 588-8300

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

John Goodgame

Akin Gump Strauss Hauer & Feld LLP

1111 Louisiana Street, 44th Floor

Houston, Texas 77002

Telephone: (713) 220-8144

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 þ (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 Issuer 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**	**Proposed Maximum Offering Price per Note**	**Proposed Maximum Aggregate Offering Price**	**Amount of Registration Fee(1)**
5.875% Senior Notes due 2022	$600,000,000	100%	$600,000,000	$69,720
Guarantees of 5.875% Senior Notes due 2022(2)				None(3)

(1) Calculated pursuant to Rule 457(f)(2) under the Securities Act of 1933, as amended.
(2) No separate consideration was received for the guarantees. Each subsidiary of Memorial Resource Development Corp. that is listed below in the Table of Subsidiary Guarantor Registrants has guaranteed the notes being registered.
(3) Pursuant to Rule 457(n) of the Securities Act of 1933, as amended, no registration fee is required for the guarantees.

The registrants hereby amend this registration statement on such date or dates as may be necessary to delay its effective date until the registrants 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 Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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TABLE OF SUBSIDIARY GUARANTOR REGISTRANTS

Exact Name of Registrant as Specified in its Charter*	State or Other Jurisdiction of Incorporation or Organization	IRS Employer Identification Number
Beta Operating Company, LLC	Delaware	46-4710769
Memorial Resource Finance Corp.	Delaware	46-4268211
MRD Operating LLC	Delaware	46-4710769

* The address for each registrant s principal executive office is 500 Dallas Street, Suite 1800, Houston, Texas 77002, and the telephone number for each registrant s principal executive office is (713) 588-8300.

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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 jurisdiction where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED APRIL 17, 2015

PROSPECTUS

Memorial Resource Development Corp.

Offer to Exchange

Up to $600,000,000 of 5.875% Senior Notes due 2022

That Have Not Been Registered under the Securities Act of 1933

For

Up to $600,000,000 of 5.875% Senior Notes due 2022

That Have Been Registered under the Securities Act of 1933

Terms of the New 5.875% Senior Notes due 2022 Offered in the Exchange Offer:

The terms of the new notes offered hereby (the new notes) are identical to the terms of our outstanding notes that were issued on July 10, 2014 (our old notes), except that the new notes will be registered under the Securities Act of 1933 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 $600,000,000 of our old notes for new notes with materially identical terms that have been registered under the Securities Act of 1933 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 , 2015, unless extended.

Tenders of old notes may be withdrawn at any time prior to the expiration of the exchange offer.

The exchange of old notes for new notes will not be a taxable event for U.S. federal income tax purposes.

You should carefully consider the risks set forth under Risk Factors beginning on page 16 of this prospectus for a discussion of factors you should consider before participating in the exchange offer.

We are an emerging growth company as that term is used in the Jumpstart Our Business Startups Act of 2012, and as such, we have elected to take advantage of certain reduced public company reporting requirements for this prospectus and future filings. See Summary Emerging Growth Company Status.

Each broker-dealer that receives new notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such new notes. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new notes received in exchange for old notes where such old notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. Please read Plan of Distribution.

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 , 2015.

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This prospectus is part of a registration statement we filed with the Securities and Exchange Commission, or the SEC. 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. If you receive any unauthorized information, you must not rely on it. 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 the date on the front cover of this prospectus.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). Forward-looking statements, which are subject to a number of risks and uncertainties, many of which are beyond our control, may include statements about our:

- business strategy;
- estimated reserves and the present value thereof;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and future operating results;
- realized commodity prices;
- timing and amount of future production of reserves;
- ability to procure drilling and production equipment;
- ability to procure oilfield labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- ability to access, and the terms of, capital;
- drilling of wells, including statements made about future horizontal drilling activities;
- competition;

- expectations regarding government regulations;
- marketing of production and the availability of pipeline capacity;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- expectations regarding general economic and business conditions;
- competition in the oil and natural gas industry;
- effectiveness of our risk management activities;
- environmental and other liabilities;
- counterparty credit risk;
- expectations regarding taxation of the oil and natural gas industry;
- expectations regarding developments in other countries that produce oil and natural gas;
- future operating results;
- plans and objectives of management; and
- plans, objectives, expectation and intentions contained in this prospectus that are not historical.

These types of statements, other than statements of historical fact included in this prospectus, are forward-looking statements. These forward-looking statements may be found in Summary, Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and other sections of this prospectus. In some cases, you can identify forward-looking statements by terminology such as may, will, could, should, expect, plan, proj forecast, intend, anticipate, believe, estimate, predict, potential, pursue, target, outlook, continu terms or other comparable terminology. These statements discuss future expectations, contain projections of results of operations or of financial condition or include other forward-looking information. These forward-looking statements involve

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risks and uncertainties. Important factors that could cause our actual results or financial condition to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- our ability to generate sufficient cash to make payments on the notes;
- variations in the market demand for, and prices of, oil, natural gas and NGLs;
- uncertainties about our estimated reserves;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our senior secured revolving credit facility;
- general economic and business conditions;
- risks associated with negative developments in the capital markets;
- failure to realize expected value creation from property acquisitions;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- drilling results;
- potential financial losses or earnings reductions from our commodity price risk management programs;
- adoption or potential adoption of new governmental regulations;
- the availability of capital on economic terms to fund our capital expenditures and acquisitions;
- risks associated with our substantial indebtedness; and
- our ability to satisfy future cash obligations and environmental costs.

The forward-looking statements contained in this prospectus are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this prospectus are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events or circumstances described in any forward-looking statement will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in the Risk Factors section of this prospectus and elsewhere in this prospectus. All forward-looking statements speak only as of the date on which they are made. We do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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NAMES OF ENTITIES

As used in this prospectus, unless we indicate otherwise:

- the Company, we, our, us and our company or like terms refer collectively to (i) Memorial Resource Development Corp. and its subsidiaries (other than MEMP and its subsidiaries) for periods after the restructuring transactions described below and (ii) our predecessor (as described below) other than MEMP and its subsidiaries for periods prior to the restructuring transactions;

- Memorial Production Partners, MEMP and the Partnership refer to Memorial Production Partners LP individually and collectively with its subsidiaries, as the context requires. We own the general partner of MEMP, which owns 50% of MEMP s incentive distribution rights;

- MEMP GP refers to Memorial Production Partners GP LLC, the general partner of the Partnership, which we own;

- MRD Holdco refers to MRD Holdco LLC, a holding company controlled by the Funds that, together as part of a group owns a majority of our common stock;

- MRD LLC refers to Memorial Resource Development LLC, which has historically owned our predecessor s business and was merged into MRD Operating LLC (MRD Operating), our 100% owned subsidiary, subsequent to our initial public offering;

- WildHorse Resources refers to WildHorse Resources, LLC, which owned our interest in the Terryville Complex and merged into MRD Operating in February 2015;

- our predecessor refers collectively to MRD LLC and its consolidated subsidiaries, consisting of Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C., Black Diamond Minerals, LLC, Beta Operating Company, LLC, MEMP GP, BlueStone, MRD Operating LLC, WildHorse Resources, LLC, Tanos Energy LLC and each of their respective subsidiaries, including MEMP and its subsidiaries;

- the Funds refers collectively to Natural Gas Partners VIII, L.P., Natural Gas Partners IX, L.P. and NGP IX Offshore Holdings, L.P., which collectively control MRD Holdco;

- restructuring transactions means the transactions that took place in connection with and shortly after the closing of our initial public offering, and pursuant to which we acquired substantially all of the assets of MRD LLC (not including its interests in BlueStone, MRD Royalty, MRD Midstream, Golden Energy Partners LLC, Classic Pipeline or MEMP subordinated units);

BlueStone refers to BlueStone Natural Resources Holdings, LLC, a subsidiary of MRD Holdco that sold substantially all of its assets in July 2013 for approximately $117.9 million;

NGP refers to Natural Gas Partners, a family of private equity investment funds organized to make direct equity investments in the energy industry, including the Funds;

MRD Royalty refers to MRD Royalty LLC, a subsidiary of MRD Holdco that owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana;

MRD Midstream refers to MRD Midstream LLC, a subsidiary of MRD Holdco that owns an indirect interest in certain midstream assets in North Louisiana; and

Classic Pipeline refers to Classic Pipeline & Gathering, LLC, a subsidiary of MRD Holdco that owns certain immaterial midstream assets in Texas.

We include a glossary of some of the oil and natural gas terms used in this prospectus in Appendix B.

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SUMMARY

This summary highlights information included in this prospectus. This summary is not complete and does not contain all of the information that you should consider before making an investment decision. You should carefully read this entire prospectus for a more complete understanding of our business and terms of the notes, as well as the tax and other considerations that are important to you, before making an investment decision. You should pay special attention to the Risk Factors section beginning on page 16 of 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 July 10, 2014 as the old notes. We refer to the new notes and the old notes collectively as the notes.

Because we control MEMP through our ownership of its general partner, we are required to consolidate MEMP for accounting and financial reporting purposes even though we only own a minority of its limited partner interests. Our financial statements include two reportable business segments: (i) the MRD Segment, which reflects all of our operations except for MEMP and its subsidiaries, and (ii) the MEMP Segment, which reflects the operations of MEMP and its subsidiaries.

Memorial Resource Development Corp.

Company Overview

We are an independent natural gas and oil company focused on the acquisition, exploration and development of natural gas and oil properties with a majority of our activity in the Terryville Complex of North Louisiana, where we are targeting overpressured, liquids-rich natural gas opportunities in multiple zones in the Cotton Valley formation.

As of December 31, 2014, our total leasehold position was 335,687 gross (210,854 net) acres. As of December 31, 2014, we had estimated proved reserves of approximately 1,632 Bcfe. As of such date, we operated 99.6% of our proved reserves, 72% of which were natural gas. For the year ended December 31, 2014, 58% of our revenues were attributable to natural gas production, 21% to NGLs and 21% to oil.

Our average net daily production for the year ended December 31, 2014 was approximately 226.9 MMcfe/d (approximately 77% natural gas, 16% NGLs and 7% oil) and our reserve life was approximately 20 years. The Terryville Complex represented 81% of our total net production for the year ended December 31, 2014. As of December 31, 2014, we produced from 129 horizontal wells and 659 vertical wells. During 2014, we completed and brought online 31 horizontal wells in the Terryville Complex, bringing our total number of producing horizontal wells to 52 in our primary formations as of December 31, 2014.

Recent Developments

Property Swap

In February 2015, we and MEMP completed a transaction (the Property Swap) in which we exchanged certain of our oil and gas properties in East Texas and non-core Louisiana for MEMP s North Louisiana oil and gas properties and approximately $78.0 million in cash, subject to customary adjustments. Terms of the transaction were approved by our board of directors and by its conflicts committee, which is comprised entirely of independent directors. The transaction had an effective date of January 1, 2015.

Amendment to Senior Secured Revolving Credit Facility and Borrowing Base Reaffirmation

On April 13, 2015, we entered into a fourth amendment to our senior secured revolving credit facility to, among other things, add new lenders and permit the repurchase of up to $50.0 million of our common stock.

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In connection therewith, the lenders under our senior secured revolving credit facility reaffirmed the borrowing base under our facility at $725 million to remain at such level until the next scheduled redetermination, the next interim redetermination or other adjustment to the borrowing base, whichever occurs first.

Corporate History and Structure

We are a Delaware corporation formed by MRD LLC in January 2014. MRD LLC was a Delaware limited liability company formed in April 2011 by the Funds to own, acquire, exploit and develop oil and natural gas properties.

We completed our initial public offering on June 18, 2014. In connection with the closing of our initial public offering, MRD LLC contributed to us substantially all of its assets, comprised of the following, in exchange for shares of our common stock (which were distributed to MRD LLC s sole member, MRD Holdco): (1) 100% of its ownership interests in Classic Hydrocarbons Holdings, L.P. (Classic), Classic Hydrocarbons GP Co., L.L.C. (Classic GP), Black Diamond Minerals, LLC (Black Diamond), Beta Operating Company, LLC, MRD Operating LLC (MRD Operating) and MEMP GP, which owns a 0.1% general partner interest and 50% of the incentive distribution rights in MEMP, and (2) its 99.9% membership interest in WildHorse Resources. In addition, certain former management members of WildHorse Resources contributed to us the remaining 0.1% membership interest in WildHorse Resources, and also exchanged their incentive units in WildHorse Resources, for shares of our common stock and cash consideration. As a result, we are majority-owned by the group consisting of MRD Holdco and certain former management members of WildHorse Resources.

Following the completion of our initial public offering, MRD LLC distributed to MRD Holdco (i) its interests in BlueStone, MRD Royalty, MRD Midstream, Golden Energy Partners LLC (Golden Energy) and Classic Pipeline; (ii) the MEMP subordinated units; (iii) the remaining cash released from its debt service reserve account in connection with the redemption of the 10.00%/10.75% Senior PIK toggle notes due 2018 (the PIK notes); and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy s assets in May 2014. We also reimbursed MRD LLC for the approximately $17.2 million interest payment that it made on the PIK notes on June 15, 2014, which was distributed to MRD Holdco.

As part of the restructuring transactions, we merged Black Diamond into MRD Operating, and MRD LLC was merged into MRD Operating upon the termination of the PIK notes indenture on June 27, 2014. WildHorse Resources merged into MRD Operating in February 2015.

In February 2015, prior to the completion of the Property Swap, each of Classic Hydrocarbons, Inc. and Classic Operating Co. LLC were merged into Classic Hydrocarbons Operating, LLC (Classic Operating). In connection with and as part of the Property Swap, Classic sold all of the equity interests owned by it in Classic Operating, Craton Energy GP III, LLC and Craton Energy Holdings III, LP to Memorial Production Operating LLC. In March 2015, Classic and Classic GP were merged into MRD Operating.

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The following diagram shows our current ownership structure.

(1) The Funds refer collectively to Natural Gas Partners VIII, L.P., Natural Gas Partners IX, L.P. and NGP IX Offshore Holdings, L.P., which collectively control MRD Holdco. The Funds collectively indirectly own 50% of the Partnership s incentive distribution rights.

(2) A group consisting of MRD Holdco and certain former management members of WildHorse Resources, LLC controls more than 50% of our common stock.

(3) Subsidiaries of MRD Holdco include Blue Stone, MRD Royalty, MRD Midstream, Golden Energy and Classic Pipeline.

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Corporate Information

Our principal executive offices are located at 500 Dallas Street, Suite 1800, Houston, Texas 77002, and our phone number is (713) 588-8300. Our website address is www.memorialrd.com. The information on our website is not part of this prospectus, and you should rely only on information contained in this prospectus when making a decision as to whether or not to tender your notes.

Emerging Growth Company Status

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

- provide an auditor s attestation report on management s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002;
- provide more than two years of audited financial statements and related management s discussion and analysis of financial condition and results of operations;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- provide certain disclosure regarding executive compensation required of larger public companies or hold shareholder advisory votes on executive compensation required by the Dodd-Frank Wall Street Reform and Consumer Protection Act; or
- obtain shareholder approval of any golden parachute payments not previously approved.

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

- the last day of the fiscal year in which we have $1.0 billion or more in annual revenues;
- the date on which we become a large accelerated filer (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30);
- the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period; or

the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

The Exchange Offer

The following summary contains basic information about the exchange offer and is not intended to be complete. For a more complete understanding of the exchange offer, please refer to the section entitled Exchange Offer in this prospectus.

Old Notes	On July 10, 2014, we issued $600 million aggregate principal amount of 5.875% Senior Notes due 2022.
New Notes	5.875% Senior Notes due 2022. The terms of the new notes are identical to the terms of 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.
Exchange Offer	We are offering to exchange up to $600 million aggregate principal amount of the new notes for an equal amount of our old notes.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on , 2015, unless we decide to extend it.
Conditions 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 SEC. The exchange offer is not conditioned on a minimum aggregate principal amount of old notes being tendered. The exchange offer is conditioned upon the effectiveness of this registration statement and certain other customary conditions. Please read Exchange Offer Conditions to the Exchange Offer for more information about the conditions to the exchange offer.
Procedures for Tendering Outstanding Notes	To participate in the exchange offer, you must follow the procedures established by The Depository Trust Company, or DTC, for tendering notes held in book-entry form. These procedures for using DTC s Automated Tender Offer Program, or 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 confirm that: DTC has received 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 of the exchange offer. 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.

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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 of the exchange offer. We will return any old notes that we do not accept for exchange to you without expense promptly after the expiration date of the exchange offer and acceptance of the old notes for exchange. Please refer to the section in this prospectus entitled Exchange Offer Terms of the Exchange Offer.
Fees and Expenses	We will bear 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 old notes for new notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please read Certain U.S. Federal Income Tax Considerations.
Exchange Agent	We have appointed U.S. Bank National Association as exchange agent for the exchange offer. You should direct questions and requests for assistance, as well as requests for additional copies of this prospectus or the letter of transmittal, to the exchange agent addressed as follows: U.S. Bank National Association, Corporate Trust Services, EP-MN-WS2N, 60 Livingston Avenue, St. Paul, MN 55107, Attn: Specialized Finance. Eligible institutions may make requests by facsimile at (651) 466-7372 and may confirm facsimile delivery by calling (651) 466-5129.

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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 the 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	Memorial Resource Development Corp.
Notes Offered	$600,000,000 aggregate principal amount of 5.875% senior notes due 2022, registered under the Securities Act. The old notes and the new notes will be treated as a single class of securities under the indenture, including, without limitation, for purposes of waivers, amendments, redemptions and offers to purchase.
Maturity	July 1, 2022.
Interest	Interest on the new notes will accrue at a rate of 5.875% per annum and will be payable semi-annually in cash in arrears on January 1 and July 1 of each year, beginning on January 1, 2015.
Ranking	Like the old notes, the new notes will be our senior unsecured obligations. Accordingly, they will rank:
	equally in right of payment to all of our existing and future senior unsecured indebtedness;
	effectively junior in right of payment to all of our existing and future secured indebtedness, including indebtedness under our senior secured revolving credit facility, to the extent of the value of the assets securing such indebtedness;
	structurally junior to all existing and future indebtedness and other liabilities of any non-guarantor subsidiaries; and
	senior in right of payment to all the Company s existing and future subordinated indebtedness.

Guarantees

Each of our guarantor subsidiaries will fully and unconditionally guarantee, jointly and severally, the new notes if and so long as such entity guarantees (or is an obligor with respect to) indebtedness (other than the notes) in excess of a de minimis amount. Not all of our future subsidiaries will be required to become a guarantor. If we cannot make payments on the new notes when they are due, the guarantors must make them instead. Please read Description of Notes Note Guarantees.

Each guarantee will rank:

equally in right of payment to all existing and future senior unsecured indebtedness of the guarantor;

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	effectively junior in right of payment to all existing and future secured indebtedness of the guarantor, including its guarantee of indebtedness under our senior secured revolving credit facility, to the extent of the value of the assets securing such indebtedness; and
	senior in right of payment to any future subordinated indebtedness of the guarantor.
Optional Redemption	The issuer will have the option to redeem all or a portion of the new notes, on any one or more occasions, on or after July 1, 2017, at the redemption prices described in this prospectus under the heading Description of Notes Optional Redemption, together with any accrued and unpaid interest to, but not including, the date of redemption. Before July 1, 2017, the issuer may redeem all or any part of the new notes at the make-whole price set forth under Description of Notes Optional Redemption. In addition, prior to July 1, 2017, the issuer may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the new notes, but in an amount not greater than the net proceeds of an equity offering at a redemption price of 105.875% of the principal amount of the new notes, plus any accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the aggregate principal amount of the new notes issued under the indenture governing the new notes remains outstanding immediately after such redemption and the redemption occurs within 180 days after the closing date of such equity offering. Please read Description of Notes Optional Redemption.
Change of Control	If a change of control event occurs, each holder of new notes may require the issuer to repurchase all or a portion of its new notes for cash at a price equal to 101% of the aggregate principal amount of such notes, plus accrued and unpaid interest, if any, to the date of repurchase.
Certain Covenants	The indenture governing the new notes contains covenants that limit, among other things, our ability and the ability of our restricted subsidiaries to: pay dividends on, purchase or redeem our common stock or purchase or redeem subordinated debt; make certain investments; incur or guarantee additional indebtedness or issue certain types of equity securities; create or incur certain liens; sell assets; consolidate, merge or transfer all or substantially all of our assets; enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;

- engage in transactions with affiliates; and
- create unrestricted subsidiaries.

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	These covenants are subject to a number of important qualifications and limitations, and our unrestricted subsidiaries (including MEMP and its subsidiaries) will not be subject to these covenants. In addition, most of the covenants will be terminated before the new notes mature if both of two specified ratings agencies assign the new notes an investment grade rating in the future and no event of default exists under the indenture governing the new notes. See Description of Notes Certain Covenants.
Transfer Restrictions; Absence of Established 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. We do not intend, however, to apply for a listing of the new notes on any securities exchange or any automated dealer quotation system. In addition, neither we nor any initial purchaser of any notes has any obligation to make a market in any notes, and any market-making activities may be discontinued at any time without notice. Therefore, we cannot assure you as to the development or continuation of an active market for the new notes or as to the liquidity of any such market.
Form of Exchange Notes	The new notes will be represented initially by one or more global notes. The global new notes will be deposited with the trustee, as custodian for DTC.
Trustee, Registrar and Exchange Agent	U.S. Bank National Association.
Governing Law	The new notes and the indenture governing the new notes will be governed by, and construed in accordance with, the laws of the State of New York.
Same-Day Settlement	The global new notes will be shown on, and transfers of the global new notes will be effected only through, records maintained in book entry form by DTC and its direct and indirect participants. The new notes are expected to trade in DTC s Same Day Funds Settlement System until maturity or redemption. Therefore, secondary market trading activity in the new notes will be settled in immediately available funds.

You should refer to the section entitled Risk Factors beginning on page 16 for an explanation of certain risks of investing in the new notes and participating in the exchange offer.

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Ratio of Earnings to Fixed Charges

The table below sets forth our ratio of earnings to fixed charges for the periods indicated on a consolidated historical basis.

	For the Year Ended December 31,		
	2014	2013	2012
Ratio of earning to fixed charges(1)	x	2.1x	1.8x

(1) Earnings were inadequate to cover fixed charges by $541.4 million for the year ended December 31, 2014 primarily related to $831.1 million of compensation expense recognized in connection with our initial public offering and restructuring transactions.

For the purpose of computing the ratio of earnings to fixed charges, the term earnings is the amount resulting from adding and subtracting the following items (as applicable). Add the following: (a) pre-tax income from continuing operations before adjustment for income or loss from equity investees; (b) fixed charges; (c) amortization of capitalized interest; (d) distributed income of equity investees; and (e) your share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges. From the total of the added items, subtract the following: (a) interest capitalized; (b) preference security dividend requirements of consolidated subsidiaries; and (c) the noncontrolling interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term fixed charges means the sum of the following: (a) interest expensed and capitalized, (b) amortized premiums, discounts and capitalized expenses related to indebtedness, (c) an estimate of the interest within rental expense, and (d) preference security dividend requirements of consolidated subsidiaries.

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Summary Historical Financial Data

The following summary historical financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated and combined financial statements and notes thereto included elsewhere in this prospectus.

Basis of Presentation. The summary financial data as of, and for the years ended, December 31, 2014, 2013, and 2012 presented below have been derived from our consolidated financial statements and our predecessor and the previous owners on a combined basis for periods prior to our initial public offering. For periods after the completion of our initial public offering, our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. Due to our control of MEMP through our ownership of MEMP GP, we are required to consolidate MEMP for accounting and financial reporting purposes. MEMP is owned 99.9% by its limited partners and 0.1% by MEMP GP.

Comparability of the information reflected in summary financial data. The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- the acquisition of working interests, royalty interests and net revenue interests located in the Permian Basin in July 2012 for a net purchase price of approximately $74.7 million;

- two separate third party acquisitions by MEMP of assets in East Texas in May and September 2012, respectively, for a combined net purchase price of approximately $126.9 million;

- multiple acquisitions of operated and non-operated interests in certain oil and natural gas properties primarily located in the Permian Basin during 2013 for an aggregate net purchase price of $75.9 million;

- the acquisition by WildHorse Resources of assets in Louisiana in March 2013 for approximately $67.1 million;

- the sale of assets by BlueStone in East Texas in July 2013 for approximately $117.9 million;

- the Eagle Ford Acquisition (as defined below) in March 2014 for a net purchase price of $168.1 million;

- the June 2014 distribution by MRD LLC of the following to MRD Holdco: (i) BlueStone, MRD Royalty, MRD Midstream, Golden Energy and Classic Pipeline; and (ii) the MEMP subordinated units;

- the contribution by certain former management members of WildHorse Resources to us of their outstanding incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources, and the issuance of 42,334,323 shares of our common stock and payment of cash consideration of $30.0 million to such former management members of WildHorse Resources and recognition of compensation expense of $831.1 million; and

the MEMP Wyoming Acquisition (as defined below) in July 2014 for a purchase price of approximately $906.1 million.

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As a result of the factors listed above, the consolidated and combined historical results of operations and period-to-period comparisons of these results and certain financial data may not be comparable or indicative of future results.

	For the Year Ended December 31, 2014	2013	2012
	(In thousands, except per share data)		
Statement of Operations Data:			
Revenues:			
Oil & natural gas sales	$ 894,967	$ 571,948	$ 393,631
Other revenues	4,378	3,075	3,237
Total revenues	899,345	575,023	396,868
Costs and expenses:			
Lease operating	161,303	113,640	103,754
Pipeline operating	2,068	1,835	2,114
Exploration	16,603	2,356	9,800
Production and ad valorem taxes	45,751	27,146	23,624
Depreciation, depletion, and amortization	314,193	184,717	138,672
Impairment of proved oil and natural gas properties	432,116	6,600	28,871
Incentive unit compensation expense	943,949	43,279	9,510
General and administrative	87,673	82,079	59,677
Accretion of asset retirement obligations	6,306	5,581	5,009
(Gain) loss on commodity derivative instruments	(749,988)	(29,294)	(34,905)
(Gain) loss on sale of properties	3,057	(85,621)	(9,761)
Other, net	(12)	649	502
Total costs and expenses	1,263,019	352,967	336,867
Operating income (loss)	(363,674)	222,056	60,001
Other income (expense):			
Interest expense, net	(133,833)	(69,250)	(33,238)
Loss on extinguishment of debt	(37,248)		
Amortization of investment premium			(194)
Other, net	(337)	145	535
Total other income (expense)	(171,418)	(69,105)	(32,897)
Income (loss) before income taxes	(535,092)	152,951	27,104
Income tax benefit (expense)	(100,971)	(1,619)	(107)
Net income (loss)	(636,063)	151,332	26,997
Net income (loss) attributable to noncontrolling interest	126,788	49,830	(2,701)
Net income (loss) attributable to Memorial Resource Development Corp.	(762,851)	101,502	29,698

Net (income) loss allocated to members	(20,305)	(90,712)	7,620
Net (income) loss allocated to previous owners	(1,425)	(10,790)	(37,318)
Net income (loss) available to common stockholders	$ (784,581)	$	$
Earnings per common share:			
Basic	$ (4.08)	n/a	n/a
Diluted	$ (4.08)	n/a	n/a
Cash Flow Data:			
Net cash flow provided by operating activities	$ 476,271	$ 277,823	$ 240,404
Net cash used in investing activities	1,816,979	367,443	606,738
Net cash provided by financing activities	1,268,945	117,950	361,761
Balance Sheet Data:			
Working capital	$ 219,580	$ 48,256	$ 63,054
Total assets	4,593,547	2,829,161	2,459,304
Total debt	2,378,413	1,663,217	939,382
Total equity	1,702,964	858,132	1,276,709

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Adjusted EBITDA

Our reportable business segments are organized in a manner that reflects how management manages those business activities.

We evaluate segment performance based on Adjusted EBITDA. The definition and calculation of Adjusted EBITDA and the reconciliation of total reportable segments Adjusted EBITDA to net income (loss) is included in the notes to our consolidated and combined financial statements included elsewhere in this prospectus.

Adjusted EBITDA (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in evaluating segment performance. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss). Our computation of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements. The following table provides a reconciliation of the MRD Segment net income to the MRD Segment Adjusted EBITDA.

Calculation of Adjusted EBITDA

	For the Year Ended December 31,		
	2014	**2013**	**2012**
	(In thousands)		
Net income (loss)	$ (762,926)	82,243	(14,641)
Interest expense, net	50,283	27,349	12,802
Loss on extinguishment of debt	37,248		
Income tax expense (benefit)	99,850	1,311	(178)
DD&A	154,917	87,043	62,636
Impairment of proved oil and natural gas properties	24,576	2,527	18,339
Accretion of AROs	688	728	632
(Gain) loss on commodity derivative instruments	(257,734)	(3,013)	(13,488)
Cash settlements received (paid) on commodity derivative instruments	9,166	12,240	30,188
(Gain) loss on sale of properties	3,057	(82,773)	(2)
Acquisition related costs	2,305	1,584	403
Incentive-based compensation expense	946,753	43,279	9,510
Exploration costs	15,813	1,226	7,337
Loss on office lease	1,180		
Non-cash equity (income) loss from MEMP	12,656	(1,847)	(696)
Cash distributions from MEMP	6,144	26,006	19,263
Adjusted EBITDA	$ 343,976	197,903	132,105

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Summary Reserve, Production and Operating Data for the MRD Segment

The following tables present summary data with respect to the estimated historical net proved oil and natural gas reserves and production and operating data for the MRD Segment as of the dates presented.

The proved reserve estimates presented in the table below were prepared by our management and audited by Netherland, Sewell & Associates, Inc. (NSAI). Regarding our properties, estimates comprising 100% of the total proved reserves in our reserve report were prepared by our management and audited by NSAI. These reserve estimates were prepared in accordance with current SEC rules regarding oil and natural gas reserve reporting. The following tables also contain certain summary information regarding production and sales of oil and natural gas with respect to such properties.

Please read Business Our Oil and Natural Gas Data as well as Management s Discussion and Analysis of Financial Condition and Results of Operations and the summary of our reserve report included herein as Appendix C in evaluating the material presented below.

Reserve Data

Estimated Proved Reserves	As of December 31, 2014
Natural gas (MMcf)	1,180,929
Oil (MBbls)	12,603
NGLs (MBbls)	62,589
Total estimated proved reserves (MMcfe)	1,632,079
Proved developed producing (MMcfe)	487,800
Proved developed non-producing (MMcfe)	47,351
Proved undeveloped (MMcfe)	1,096,928
Proved developed reserves as a percentage of total proved reserves	33%
PV-10 of proved reserves (in millions)(1)	3,021,348

(1) PV-10 is a non-GAAP financial measure and differs from standardized measure, the most directly comparable GAAP financial measure. Please see Business Our Oil and Natural Gas Data Reconciliation of PV-10 to Standardized Measure.

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Production and Operating Data

	For the Year Ended December 31, 2014	2013	2012
Production and operating data:			
Oil (MBbls)	951	665	369
NGLs (MBbls)	2,220	1,457	898
Natural gas (MMcf)	63,801	34,092	24,130
Total (MMcfe)	82,815	46,819	31,731
Average net production (MMcfe/d)	226.9	128.3	86.7
Average sales price:			
Oil (per Bbl)	$ 89.54	$ 100.76	$ 95.56
NGL (per Bbl)	38.62	36.99	40.78
Natural gas (per Mcf)	3.67	3.22	2.74
Total (Mcfe)	$ 4.89	$ 4.93	$ 4.35
Average unit costs per Mcfe:			
Lease operating expense	$ 0.32	$ 0.53	$ 0.77
Production and ad valorem taxes	$ 0.17	$ 0.20	$ 0.24
General and administrative expenses	$ 0.51	$ 0.82	$ 0.91
Depletion, depreciation, and amortization	$ 1.87	$ 1.86	$ 1.97

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RISK FACTORS

Investing in our notes involves risk. Before making an investment decision, you should carefully consider the risk factors discussed in this prospectus, together with all of the other information included in this prospectus or to which we refer you. If any of these risks were to occur, our business, financial condition or results of operations could be adversely affected. Additional risks and uncertainties not presently known to us or not believed by us to be material may also negatively impact us. Also, please read Cautionary Statement Regarding Forward-Looking Statements in this prospectus.

Risks Related to the Notes

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.

We have, and after the consummation of this exchange offer will continue to have, a substantial amount of indebtedness. As of December 31, 2014, we had approximately $783 million of total indebtedness, including the notes, and approximately $542 million of available borrowing capacity under our senior secured revolving credit facility. The terms and conditions governing our indebtedness, including the notes and senior secured revolving credit facility:

- 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 and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increase our vulnerability to economic downturns and adverse developments in our business;
- 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;
- 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
- limit management s discretion in operating our business.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough money, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. For example, our existing and future debt agreements will require that we satisfy certain conditions, including coverage and leverage ratios, to borrow money. Our existing and future debt agreements will also restrict the payment of dividends and distributions by certain of our subsidiaries to us, which could affect our access to cash. In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations.

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We may not be able to generate enough cash flow to meet our debt obligations and may be forced to take other actions to satisfy our debt obligations which may not be successful.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Moreover, and subject to certain limitations, we and our subsidiaries may be able to incur substantial additional indebtedness in the future. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and from our subsidiaries and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing, could materially and adversely affect our ability to make payments on our indebtedness and our business, financial condition and results of operations.

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

The notes and the guarantees are unsecured and effectively subordinated to our and the guarantors existing and future secured indebtedness.

The new notes and the guarantees, like the old notes and guarantees, will be general unsecured senior obligations ranking effectively junior in right of payment to all of our existing and future secured debt and that of each guarantor, including obligations under our senior secured revolving credit facility, to the extent of the value of the assets securing such debt. If any of the Company or a guarantor is declared bankrupt, becomes insolvent or is liquidated or reorganized, its secured debt will be entitled to be paid in full from the assets securing that debt before any payment may be made with respect to the notes or the affected guarantees. Holders of the notes will participate ratably with all holders of our other unsecured indebtedness that does not rank junior to the notes, including all of our other general creditors, based upon the respective amounts owed to each holder or creditor, in any proceeds from our remaining assets. In any of the foregoing events, we cannot assure you that there will be sufficient assets to pay amounts due on the notes. As a result, holders of the notes would likely receive less, ratably, than holders of secured indebtedness.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our senior secured revolving credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease. If interest rates on our senior secured revolving credit facility increased by 1%, cash interest expense for the year ended December 31, 2014 would have increased by approximately $0.8 million.

Despite our current level of indebtedness, we and our subsidiaries may still be able to incur substantially more debt. This could further exacerbate the risks associated with our and our subsidiaries substantial indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future, subject to certain limitations. If new debt is added to our or our subsidiaries current debt levels, the related risks that we now face could increase. Our level of indebtedness and our subsidiaries level of indebtedness could, for instance, prevent us or our subsidiaries from engaging in transactions that might otherwise be beneficial to us or our subsidiaries or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations, including those relating to the notes, and those of our subsidiaries.

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

Upon the occurrence of certain change of control events, we would be required to offer to repurchase all or any part of the notes then outstanding for cash at 101% of the principal amount plus accrued and unpaid interest, if any. The source of funds for any repurchase required as a result of any change of control will be our available cash or cash generated from our operations or other sources, including:

- borrowings under our senior secured revolving credit facility or other sources;
- sales of assets; or
- sales of equity.

We cannot assure you that sufficient funds would be available at the time of any change of control to repurchase your notes after first repaying any of our other senior debt that may exist at the time. In addition, restrictions under our senior secured revolving credit facility will not allow such repurchases and additional credit facilities we enter into in the future also may prohibit such repurchases. Additionally, using available 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.

A guarantee could be voided if it constitutes a fraudulent transfer under U.S. bankruptcy or similar state law, which would prevent the holders of the notes from relying on the subsidiary guarantor to satisfy claims.

Under U.S. bankruptcy law and comparable provisions of state fraudulent transfer laws, any guarantee of the notes can be voided, or claims under the guarantee may be subordinated to all other debts of the guarantor if, among other things, the guarantor, at the time it incurred the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee, received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and:

- was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which such guarantor s remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

A court may find that a guarantor did not receive reasonably equivalent value or fair consideration for its guarantee if such guarantor did not substantially benefit directly or indirectly from the issuance of the guarantee. If a court were to void a guarantee, you would no longer have a claim against that guarantor. Absent further findings from the court, you would, however, retain your claim against the remaining entities. Sufficient funds to repay the notes may not be available from other sources, if any. In addition, the court might direct you to repay any amounts that you already received from such guarantor.

The measures of insolvency for purposes of fraudulent transfer laws vary depending upon the governing law. Generally, a guarantor would be considered insolvent if:

- the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all its assets;
- the present fair saleable value of its assets is less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or
- it could not pay its debts as they become due.

A guarantee may also be voided, without regard to the above factors, if a court finds that the guarantor entered into the guarantee with the actual intent to hinder, delay or defraud its creditors.

The indenture contains a provision intended to limit each guarantor s liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent transfer. Such provision may not be effective to protect the guarantee from being voided under fraudulent transfer law.

A financial failure by us or an affiliated entity may result in the assets of any or all of those entities becoming subject to the claims of all creditors of those entities or in the non-consensual modification of the terms of the notes.

A financial failure by us or an affiliated entity could affect payment of the notes if a bankruptcy court were to substantively consolidate us and our operating subsidiaries. If a bankruptcy court substantively consolidated us and an affiliated entity, the consolidated assets of the entities would become subject to the claims of creditors of all entities.

This would expose holders of notes not only to the usual impairments arising from bankruptcy, but also to potential dilution of the amount ultimately recoverable because of the potentially larger creditor base. Furthermore, forced restructuring of the notes could occur through the cram-down provisions of the bankruptcy code. Under these provisions, the notes could be restructured over your objections as to their general terms, primarily interest rate and maturity.

There is no established market for the notes.

The new notes generally will be freely transferable. We do not intend, however, to apply for a listing of the notes on any securities exchange or any automated dealer quotation system. The initial purchasers have advised us that they intend to make a market in the notes as permitted by applicable laws and regulations; however, the initial purchasers are not obligated to make a market in any of the notes, and they may discontinue their market making activities at any time without notice. Therefore, an active market for any of the notes may not develop or, if developed, may not continue. The liquidity of any market for the notes will depend upon various factors, including, the number of holders of the notes, our performance, the market for similar securities, the interest of securities dealers in making a market in the notes and the prospects for companies in our industry generally. A liquid trading market may not develop for the notes. If a market develops, the notes could trade at prices that may be lower than the initial offering price of the notes. If an active market does not develop or is not maintained, the price and liquidity of the notes may be adversely affected.

Furthermore, historically, the market for non-investment grade debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes. We cannot assure you that the market, if any, for the notes will be free from similar disruptions or that any such disruptions will not adversely affect the prices at which you may sell your notes. As has been evident in connection with the past turmoil in global financial markets, the entire high-yield debt market can experience sudden and sharp price swings, which can be exacerbated by factors such as (1) large or sustained sales by major investors in high-yield debt, (2) a default by a high profile issuer, or (3) simply a change in investors psychology regarding high-yield debt. A real or perceived economic downturn or higher interest rates could cause a decline in the market value of the notes. Moreover, if one of the major rating agencies lowers our credit rating or the credit rating of the notes, the market value of such notes will likely decline. Therefore, we cannot assure you that you will be able to sell your notes at a particular time or, in the event you are able to sell your notes, that the price that you receive when you sell will be favorable.

Many of the covenants contained in the indenture will be terminated if the notes are rated investment grade by both 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 terminate if the notes are rated investment grade by both Standard & Poor s and Moody s provided at such time no default has occurred and is continuing. The 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. However, there can be no assurance that the notes will ever be rated investment grade, or that if they are rated investment grade, that the notes will maintain such rating. See Description of Notes Certain Covenants.

Because we are a holding company, we are financially dependent on receiving distributions from our subsidiaries.

We are a holding company and our assets consist primarily of the equity interests in our operating subsidiaries. Our rights and the rights of our creditors, including the holders of the notes, to participate in the distribution of assets of any entity in which we own an equity interest will be subject to prior claims of the entity s creditors upon the entity s liquidation or reorganization. However, we may ourselves be a creditor with recognized claims against this entity, but our claims would still be subject to the prior claims of any secured creditor of this entity and of any holder of indebtedness of this entity that is senior to that held by us. Accordingly, a holder of our debt securities, including holders of the notes, may be deemed to be effectively subordinated to those claims.

Risks Related to the 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 requires 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.

The consummation of the exchange offer may not occur.

We are not obligated to complete the exchange offer under certain circumstances. See Exchange Offer Conditions to the Exchange Offer. Even if the exchange offer is completed, it may not be completed on the schedule described in this prospectus. Accordingly, holders participating in the exchange offer may have to wait longer than expected to receive their new notes, during which time those holders of old notes will not be able to effect transfers of their old notes tendered in the exchange offer.

You may be required to deliver prospectuses and comply with other requirements in connection with any resale of the new notes.

If you tender your old notes for the purpose of participating in a distribution of the new notes, you will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale of the new notes. In addition, if you are a broker-dealer that receives new notes for your own account in exchange for old notes that you acquired as a result of market-making activities or any other trading activities, you will be required to acknowledge that you will deliver a prospectus in connection with any resale of such new notes.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and will greatly affect our business, results of operations, liquidity and financial condition.

Our revenues, operating results, profitability, liquidity, future growth and the value of our assets depend primarily on prevailing commodity prices. Historically, oil and natural gas prices have been volatile and fluctuate in response to changes in supply and demand, market uncertainty, and other factors that are beyond our control, including:

- the regional, domestic and foreign supply of oil, natural gas and NGLs;
- the level of commodity prices and expectations about future commodity prices;
- the level of global oil and natural gas exploration and production;
- localized supply and demand fundamentals, including the proximity and capacity of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;

the cost of exploring for, developing, producing and transporting reserves;

the price and quantity of foreign imports;

political and economic conditions in oil producing countries;

the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

speculative trading in crude oil and natural gas derivative contracts;

the level of consumer product demand;

- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting exploration and production operations and overall energy consumption;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action;
- the price and availability of competitors supplies of oil and natural gas and alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For example, for the five years ended December 31, 2014, the NYMEX-WTI oil future price ranged from a high of $113.93 per Bbl to a low of $53.27 per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $6.15 per MMBtu to a low of $1.91 per MMBtu. Recently, oil and natural gas prices have declined significantly. Through December 31, 2014, the West Texas Intermediate posted price had declined from a high of $107.26 per Bbl on June 20, 2014 to $53.27 per Bbl on December 31, 2014. In addition, the Henry Hub spot market price had declined from a high of $6.15 per MMBtu on February 19, 2014 to a low of $2.89 per MMBtu on December 31, 2014. Any further substantial decline in commodity prices will likely have a material adverse effect on our operations and financial condition, as well as on our level of expenditures for the development of our reserves.

NGLs comprised 23% of our estimated proved reserves and accounted for 16% of our production on a volume equivalent basis for the year ended December 31, 2014. Realized NGL prices have decreased recently principally due to significant supply. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. A further or extended decline in NGL prices could materially and adversely affect our future business, financial condition and results of operations.

The prices that we receive for our oil and natural gas production often reflect a regional discount, based on the location of production, to the relevant benchmark prices, such as WTI or Brent, that are used for calculating hedge positions. The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. These discounts, if significant, could adversely affect our results of operations and financial condition.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

As a recently formed public company, growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. In addition, the failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Unless we replace the oil and natural gas reserves we produce, our revenues and production will decline, which would adversely affect our business, results of operations, liquidity and financial condition.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production and

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therefore our cash flow and financial condition are highly dependent on our success in efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we drill additional wells or make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production on economically acceptable terms, which would adversely affect our business, financial condition and results of operations.

If commodity prices continue to decline, a significant portion of our development projects may become uneconomic and cause write downs of the value of our oil and natural gas properties, which may adversely affect our financial condition and liquidity.

As discussed above, recently oil, natural gas, and NGL prices, have declined significantly. A further or extended decline in commodity prices could render many of our development and production projects uneconomic and result in a reduction of our estimated reserves, which would reduce the borrowing base under our senior secured revolving credit facility and our ability to finance planned or desired capital expenditures or acquisitions.

Deteriorating commodity prices may cause us to recognize impairments in the value of our properties. In addition, if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment or otherwise adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks. For example, we cannot assure you that wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry holes but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then-realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- loss of well control;
- title problems;

facility or equipment malfunctions;

unexpected operational events;

shortages or delivery delays or increases in the cost of equipment and services;

reductions in oil, natural gas and NGL prices;

lack of proximity to and shortage of capacity of transportation facilities;

the limited availability of financing at acceptable rates;

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- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases; and

- adverse weather conditions and natural disasters.

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. In the event that planned operations are delayed or cancelled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition and results of operations may be adversely affected.

Part of our strategy involves using 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 horizontal wells include, but are not limited to, the following:

- 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 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.

If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We own a significant amount of unproved property, which we expect to further our development efforts. We intend to continue to undertake acquisitions of unproved properties in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, 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.

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 oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2014, we had 27,827 gross (18,891 net) acres scheduled to expire in 2015, 37,342 gross (24,440 net) acres scheduled to expire in 2016, and 24,169 gross (14,223 net) acres scheduled to expire in 2017. 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 pool, 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 2015 and 2016 in the Terryville Complex, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy these rigs when needed, or that commodity prices will warrant operating such a drilling program. Any such losses of leases could materially and adversely affect the growth of our asset base, cash flows and results of operations.

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

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

Our project areas, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

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. At December 31, 2014, 27 gross (22.9 net) wells were in various stages of drilling and completion. 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. From January 2012 through December 31, 2014, we have drilled 87 gross (70.3 net) wells and none of the wells were dry holes.

Our identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our ability to drill and develop our identified potential drilling locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory changes and approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, drilling results, construction of infrastructure, inclement weather, and lease expirations.

Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional analysis of data. We cannot predict in advance of drilling and testing whether any particular drilling location will yield production in sufficient quantities to recover drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas reserves exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We also have limited experience in drilling horizontal wells in the zones of the Terryville Complex to which we have ascribed a substantial majority of our gross identified drilling locations. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in our areas of operations may not be indicative of future or long-term production rates.

Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas reserves from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operations.

We have identified drilling, recompletion and development locations and prospects for future drilling, recompletion and development. These drilling, recompletion and development locations represent a significant part of our future drilling and enhanced recovery opportunity plans. Our ability to drill, recomplete and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, and drilling results. Because of these uncertainties, we cannot be certain of the timing of these activities or that they will ultimately result in the realization of estimated proved reserves or meet our expectations for success. As such, our actual drilling and enhanced recovery activities may materially differ from our current expectations, which could have a significant adverse effect on our estimated reserves, financial condition and results of operations.

The development of our proved undeveloped and unproved reserves may take longer and may require higher levels of capital expenditures than we anticipate and may not be economically viable.

Approximately 67% of our total proved reserves at December 31, 2014 were proved undeveloped reserves; those reserves may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in our reserve report assumes that substantial capital expenditures are required to develop such undeveloped reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce future net revenues of our estimated proved undeveloped 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 reserves as proved undeveloped reserves.

Our acquisition and development operations require substantial capital expenditures.

The development and production of our oil and natural gas reserves requires substantial capital expenditures. If our revenues decrease, as a result of lower oil or natural gas prices or for any other reason, we may not be able to obtain the capital necessary to sustain our operations at our current level. In addition, our ability to acquire additional properties will be adversely affected if we are unable to fund such acquisitions from cash flow from operations or other sources.

Shortages of rigs, equipment and crews could delay our operations, increase our costs and delay forecasted revenue.

Higher oil and natural gas prices generally increase the demand for rigs, equipment, supplies and crews and can lead to shortages of, and increasing costs for, development equipment, supplies, services and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and impact our development plan, which would thus affect our financial condition and results of operations.

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Our hedging strategy may not effectively mitigate the impact of commodity price volatility from our cash flows, and our hedging activities could result in cash losses and may limit potential gains.

We intend to maintain a portfolio of commodity derivative contracts. These commodity derivative contracts include natural gas, oil and NGL financial swaps, put options and collar contracts and natural gas basis financial swaps. The prices and quantities at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil and natural gas prices and price expectations at the time we enter into these transactions, which may be substantially higher or lower than current or future oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas prices received for our future production. In addition, our senior secured revolving credit facility limits our ability to enter into commodity hedges covering greater than 85% of our reasonably anticipated projected production. Many of the derivative contracts to which we will be a party will require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets or other unforeseen events could lead to sudden changes in a counterparty s liquidity, which could impair its ability to perform under the terms of a derivative contract and, accordingly, prevent us from realizing the benefit of such a derivative contract.

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

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

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

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

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

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

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Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

SEC rules could limit our ability to book additional PUDs in the future.

SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. Moreover, we may be required to write down our PUDs if we do not drill those wells within the required five-year timeframe.

The standardized measure of our estimated proved reserves and our PV-10 is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves.

The present value of future net cash flows from our proved reserves shown in this prospectus, or standardized measure, and our PV-10 may not be the current market value of our estimated natural gas and oil reserves. In accordance with rules established by the SEC and the Financial Accounting Standards Board (FASB), we base the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows 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 natural gas and oil industry in general.

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

Our producing properties are geographically concentrated in North Louisiana. At December 31, 2014, 85.6% of our total estimated proved reserves and for the year ended December 31, 2014, 86.1% of our net average daily production was 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, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis, the United States mortgage market and a weak real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and NGLs, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the

United States or abroad deteriorates further, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and NGLs from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations and financial condition.

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Expenses not covered by our insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including natural disasters, the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, all of which could cause substantial financial losses. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The location of any properties and other assets near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations, substantial revenue losses and repairs to resume operations.

We maintain insurance coverage against potential losses that we believe is customary in the industry. However, these policies may not cover all liabilities, claims, fines, penalties or costs and expenses that we may incur in connection with our business and operations, including those related to environmental claims. Pollution and environmental risks generally are not fully insurable. In addition, we cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

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

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

- the validity of our assumptions about estimated proved reserves, future production, revenues, capital expenditures, operating expenses and costs;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- an inability to obtain satisfactory title to the assets we acquire; and
- potential lack of operating experience in the geographic market where the acquired assets or business are located.

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.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

NGP, the Funds and their affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses.

Our governing documents provide that NGP and the Funds and their respective affiliates (including NGP and its affiliates portfolio investments) are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, NGP and the Funds and their respective affiliates may acquire, develop or dispose of additional oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets.

NGP and the Funds are established participants in the oil and natural gas industry, and have resources greater than ours, which factors may make it more difficult for us to compete with them with respect to commercial activities as well as for potential acquisitions. As a result, competition from these affiliates could adversely impact our results of operations.

We may be unable to compete effectively with larger companies.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas, and securing equipment and trained personnel. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis, and many of our competitors have access to capital at a lower cost than that available to us. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development and production operations, engage in acquisition activities and replace our production. We intend to rely on cash flow from operating activities and borrowings under our senior secured revolving credit facility as our primary sources of liquidity. We also may engage in asset and equity sale transactions to, among other things, fund capital expenditures when market conditions permit us to complete transactions on terms we find acceptable. There can be no assurance that such sources will be sufficient to fund our exploration, development and acquisition activities. If our revenues and cash flows decrease in the future as a result of a further decline in commodity prices or a reduction in production levels, however, and we are unable to obtain additional equity or debt financing in the capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production levels.

Our business depends in part on pipelines, gathering systems and processing facilities owned by us or others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, gathering systems and processing facilities owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of contracted capacity on such systems. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided with only limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil and natural gas production and harm our business.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical, which could have a material adverse impact on our financial condition and results of operations.

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

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

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.

Our natural gas and oil exploration, production, and transportation operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment and thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, and results of operations.

Our oil and natural gas development and production operations are also subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of a permit before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency, or the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue.

Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected. Please read Business Regulation of Environmental and Occupational Health and Safety Matters for a further description of the laws and regulations that affect us.

Climate change legislation or regulations restricting emissions of greenhouse gases, or GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases (GHGs), including carbon dioxide and methane, may be contributing to warming of the earth s atmosphere and other climatic changes. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act (CAA) that establish Prevention of Significant Deterioration, or PSD, and Title V permit reviews for GHG emissions from certain large stationary sources. On June 23, 2014, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD or Title V programs. The EPA has announced that it is currently evaluating the decision and awaiting further action by the courts, and that it will provide relevant guidance on GHG permitting requirements.

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The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources on an annual basis in the United States, including, among others, certain oil and natural gas production facilities, which includes certain of our operations. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. In addition, the Obama administration has announced in its Climate Action Plan that it intends to adopt additional regulations to reduce emissions of GHGs in the coming years, possibly including further restrictions on emissions of methane from oil and gas operations.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Please read Business Regulation of Environmental and Occupational Health and Safety Matters for a further description of the laws and regulations that affect us.

The listing of a species as either threatened or endangered under the federal Endangered Species Act could result in increased costs and new operating restrictions, loss of leasehold or delays on our operations, which could adversely affect our results of operations and financial condition.

The federal Endangered Species Act (ESA) and analogous state laws restrict activities that may adversely affect endangered and threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. Numerous species have been listed or proposed for protected status in areas in which we currently, or could in the future, undertake operations. For instance, the American burying beetle and the lesser prairie chicken both have habitat in some areas where we operate. The U.S. Fish and Wildlife Service (FWS) identified the lesser prairie chicken, which inhabits portions of Colorado, Kansas, Nebraska, New Mexico, Oklahoma and Texas, as candidate for listing in 1998 and has listed it as threatened in March 2014. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, pursuant to which such parties agreed to take steps to protect the lesser prairie chicken s habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken s habitat. The threatened species status of the lesser prairie chicken is currently subject to a pending lawsuit by at least three states. The lawsuit challenges FWS recent classification of the lesser prairie chicken. The presence of protected species in areas where we operate could impair our ability to timely complete or carry out those operations, lose leaseholds as we may not be permitted to timely commence drilling operations, cause us to incur increased costs arising from species protection measures, and, consequently, adversely affect our results of operations and financial position.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations. See Business Regulation of Environmental and Occupational Health and Safety Matters and Business Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect the third parties on whom we rely.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, or CFTC, adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities. Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC has issued a large number of rules to implement the Dodd-Frank Act, including a rule establishing an end-user exception to mandatory clearing, referred to herein as the End-User Exception, and a rule imposing position limits, referred to herein as the Initial Position Limit Rule. The Initial Position Limit Rule was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia on September 28, 2012. The CFTC proposed a new version of the Initial Position Limit Rule in November 2013, referred to herein as the Re-Proposed Position Limit Rule, with respect to which the comment period has closed but a final rule has not been issued. The CFTC and bank regulators in September 2014 reproposed rules which would impose margin requirements on uncleared swaps between banks, swap dealers and major swap participants, referred to herein as the Re-Proposed SD/MSP Margin Rule.

We qualify as a non-financial entity for purposes of the End-User Exception and we utilize such exception so our hedging activity is not subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End-User Exception and, if the Re-Proposed SD/MSP Margin Rule is adopted, will be subject to such rule and required to post margin in accordance with such rule in connection with their swaps with other banks, swap dealers and major swap participants. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule and the Re-Proposed SD/MSP Margin Rule are ultimately effected, such proposed rules could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. 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 contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

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Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. We routinely apply hydraulic fracturing techniques in our drilling and completion programs.

While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the Safe Drinking Water Act, or the SDWA, involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Although the EPA is not the permitting authority for the SDWA s Underground Injection Control Class II programs in Louisiana, Texas, Wyoming, New Mexico, or Colorado, where we or MEMP maintain operational acreage, the EPA is encouraging state programs to review and consider use of such draft guidance. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. On April 7, 2015, the EPA published in the Federal Register a proposed rule requiring federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting flowback, as well as produced water. If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. The proposed rule is undergoing a public comment period, which ends on June 8, 2015. Moreover, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014.

In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules could require a number of modifications to our operations including the installation of new equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely to be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rules addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On December 19, 2014, the EPA released final updates and clarifications to the NSPS standards. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, on March 26, 2015, the federal Bureau of Land Management published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, development of appropriate plans for managing flowback water that returns to the surface, increased standards for interim storage of recovered waste fluids, and submission to the Bureau of Land Management of detailed information on the geology, depth and location of preexisting wells. This rule will take effect on June 24, 2015, although it is the subject of several pending lawsuits recently filed by industry groups and at least one state.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft report is expected to be released for public comment; however the report is still pending. The EPA s study could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing.

Additionally, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Certain states, including Texas and Colorado, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, in October 2011, the Louisiana Department of Natural Resources adopted new rules requiring the public disclosure of the composition and volume of fracturing fluids used in hydraulic fracturing operations. Also, October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments also clarify the Commission s authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The disposal well rule amendments became effective November 17, 2014. Furthermore, in May 2013, the Texas Railroad Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local level, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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

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

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in our exploration and production operations, could adversely impact our operations. Moreover, the imposition of new environmental requirements 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 Federal Water Pollution Control Act (the CWA) imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Also, the EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

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

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may, among other things: (i) require us to obtain a variety of permits or other authorizations governing air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, producing and other operations; (ii) regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; (iii) limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; (iv) require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or (v) impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders or injunctions limiting or requiring discontinuation of certain operations. Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, the risk of accidental and/or unpermitted spills or releases from our operations could expose us to significant liabilities, penalties and other sanctions under applicable laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, financial condition and results of operations could be materially adversely affected.

We are not the only partners in MEMP, and MEMP s partnership agreement requires it to distribute all available cash to its partners, including public unitholders.

MEMP is a publicly traded limited partnership. We own MEMP GP, the sole general partner of MEMP, and are entitled to 50% of any cash distributed in respect of MEMP s incentive distribution rights. MEMP s

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partnership agreement requires it to distribute, on a quarterly basis, 100% of its available cash to its partners. We receive only our proportionate share of cash distributions from MEMP based on our partner interests in it. The remainder of the quarterly cash distributions is distributed, pro rata, to the public unitholders (and, in the case of 50% of the incentive distribution rights, to the Funds).

For MEMP, available cash is generally all cash on hand at the end of each quarter, after payment of fees and expenses and the establishment of cash reserves by its general partner. MEMP GP determines the amount and timing of cash distributions by MEMP and has broad discretion to establish and make additions to MEMP s reserves in amounts the general partner determines to be necessary or appropriate:

- to provide for the proper conduct of partnership business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;
- to comply with applicable law, any of MEMP s debt instruments or other agreements; and
- to provide funds for distributions to the unitholders and the general partner for any one or more of the next four calendar quarters.

Accordingly, cash distributions we receive on our MEMP partner interests may be reduced at any time, or we may not receive any cash distributions from MEMP.

The amount of cash that MEMP will be able to distribute to us principally depends upon the amount of cash it can generate from its oil and natural gas production business.

A significant decline in MEMP s earnings or cash distributions would have a negative impact on its distributions to its partners, including us. The amount of cash that MEMP will be able to distribute to its partners, including us, each quarter principally depends upon the amount of cash it can generate from its oil and natural gas production business. That amount of cash will fluctuate from quarter to quarter based on, among other things:

- the amount of oil, natural gas and NGLs MEMP produces;
- the prices at which MEMP sells its oil, natural gas and NGL production;
- the amount and timing of settlements of its commodity derivatives;
- the level of MEMP s operating costs, including maintenance capital expenditures and payments to MEMP GP and its affiliates; and

the level of MEMP s interest expense, which depends on the amount of its indebtedness and the interest payable thereon.

Because of these factors, MEMP may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. In addition, the incentive distribution rights are only entitled to distributions from MEMP in any quarter if MEMP has paid at least $0.54625 on each outstanding common unit for such quarter. If MEMP reduces its per unit distribution below such amounts, we will receive less cash.

Conflicts of interest may arise because the board of directors of MEMP GP has a fiduciary duty to manage the general partner in a manner that is beneficial to the owner of MEMP GP, and at the same time, to manage MEMP in a manner that is beneficial to the MEMP unitholders. Conflicts may also arise because our executive officers have significant equity interests in MEMP.

We own MEMP GP, the sole general partner of MEMP. MEMP is a publicly traded limited partnership. The board of directors of MEMP GP owes specified duties to the MEMP unitholders, and also owes specified duties to us as owner of MEMP GP. As a result of these conflicts, the board of directors of MEMP GP may favor the interests of the MEMP public unitholders over our interests. Our executive officers have significant equity interests in MEMP. As of January 9, 2015, Mr. Weinzierl, our Chief Executive Officer, owns 556,420 MEMP

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common units; Mr. Scarff, our President, owns 96,943 MEMP common units; Mr. Cozby, our Senior Vice President and Chief Financial Officer, owns 152,424 MEMP common units; Mr. Forney, our Senior Vice President and Chief Operating Officer, owns 142,895 MEMP common units; Mr. Roane, our Senior Vice President, General Counsel and Corporate Secretary, owns 86,825 MEMP common units; and Mr. Robbins, our Senior Vice President, Corporate Development, owns 89,707 MEMP common units. As a result of our executive officers significant holdings of MEMP common units, our executive officers may favor the interests of MEMP over our interests.

If MEMP s unitholders remove MEMP GP, we would lose our general partner interest and incentive distribution rights in MEMP and the ability to manage MEMP.

We currently manage our investment in MEMP through our ownership interest in MEMP GP. MEMP s partnership agreement, however, gives unitholders of MEMP the right to remove its general partner upon the affirmative vote of holders of 66 2/3% of the MEMP s outstanding units. If MEMP GP were removed as general partner of MEMP, it would receive cash or common units in exchange for its 0.1% general partner interest and incentive distribution rights and would also lose its ability to manage MEMP. While the cash or common units the general partner would receive are intended under the terms of MEMP s partnership agreement to fully compensate MEMP GP in the event such an exchange is required, the value of the investments we make with the cash or the common units may not over time be equivalent to the value of the general partner interest and the incentive distribution rights had MEMP GP retained them.

Our business could be adversely affected by security threats, including cyber-security threats, and related disruptions.

We rely heavily on our information systems, and the availability and integrity of these systems are essential for us to conduct our business and operations. As a producer of natural gas and oil, we face various security threats, including cyber-security threats, to gain unauthorized access to our sensitive information or to render our information or systems unusable, and threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing and other facilities, refineries and pipelines. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our implementation of various procedures and controls to monitor and mitigate such security threats and to increase security for our information, systems, facilities and infrastructure may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of, or damage to, sensitive information or facilities, infrastructure and systems essential to our business and operations, as well as data corruption, communication interruptions or other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position, results of operations and cash flows.

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EXCHANGE OFFER

Purpose and Effect of the Exchange Offer

At the closing of the offering of the old notes, we and the guarantors entered into a registration rights agreement with the initial purchasers pursuant to which we and the guarantors 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, and

- use commercially reasonable efforts to have the exchange offer completed on or before July 10, 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 commercially reasonable efforts to cause the exchange offer registration statement to be effective continuously, and to keep the exchange offer open for a period of not less than 20 business days.

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 or, if no interest has been paid on such old note, from July 10, 2014. The registration rights agreement also provides an agreement 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 use commercially reasonable efforts to maintain the effectiveness of the exchange offer registration statement for these purposes for a period ending on the earlier of 180 days from the date on which the exchange offer registration statement is declared effective and the date on which the broker-dealer is no longer required to deliver a prospectus in connection with market-making or other trading activities.

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.

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

- the exchange offer is not permitted by applicable law or SEC policy;
- the exchange offer is for any reason not consummated on or before July 10, 2015 and the old notes are not freely tradable prior to that date; or
- prior to July 10, 2015, any holder notifies us that:
  - the holder is prohibited by applicable law or SEC policy from participating in the exchange offer;
  - the holder may not resell the new notes acquired in the exchange offer to the public without delivering a prospectus, and the prospectus contained in the exchange offer is not appropriate or available for such resales by such purchaser; or
  - the holder is a broker-dealer and holds old notes acquired directly from us or one of our affiliates that are not freely tradable, and such holder cannot participate in the exchange offer.

We have agreed to use commercially reasonable efforts to cause any shelf registration statement to be declared effective by the SEC (or automatically become effective under the Securities Act) on or before the 90th day after the shelf filing deadline. The shelf filing deadline shall be 20 business days after the later of (i) the date we receive notice of the above circumstances by any holder and (ii) the first to occur of (a) the date that we deliver the new notes to the registrar under the indenture of the new notes in the same aggregate principal amount as the aggregate principal amount of the old notes that were tendered by the holders of the old notes pursuant to an exchange offer and (b) July 10, 2015. We have also agreed to use commercially reasonable efforts to keep the shelf registration statement continuously effective from the date on which the shelf registration statement is declared effective by the SEC until the earlier of the first anniversary of the effective date of such shelf registration statement and such time as all notes covered by the shelf registration statement have been sold or are freely tradable. We refer to this period as the shelf effectiveness period.

The registration rights agreement provides that, in the event (i) the exchange offer is not consummated on or prior to July 10, 2015, (ii) a shelf registration statement, if required, is not declared effective (or does not automatically become effective) on or prior to the 90th calendar day following any shelf filing deadline, or (iii) any required shelf registration statement ceases to remain effective or becomes unusable in connection with resale for more than 30 calendar days (each such event referred to in clauses (i) through (iii) above, a Registration Default), the interest rate on the old notes will be increased by 0.25% per annum for the first 90-day period immediately following July 10, 2015 and by an additional 0.25% per annum with respect to each subsequent 90-day period, up to a maximum additional interest rate of 1.00% per annum thereafter, until the earlier of the completion of the exchange offer or until no Registration Default is in effect, at which time the increased interest shall cease to accrue and shall be reduced to the original interest rate of the old notes.

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 will be required to deliver information to be used in connection with any shelf registration statement and to provide comments on any 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.

If we effect the registered exchange offer, we will be entitled to close the registered exchange offer 20 business days after its commencement as long as we have accepted all old notes validly tendered in accordance with the terms of the exchange offer and no brokers or dealers continue to hold any old notes.

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, a copy of which is filed as an exhibit to the registration statement that includes this prospectus.

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

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 a 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, $600,000,000 in aggregate principal amount of the old notes is outstanding. This prospectus and the letter of transmittal are being sent to DTC, as the sole registered holder of old notes, and to its direct participants whom we can identify as holding 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 Exchange Act, 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 Fees and Expenses for more details regarding fees and expenses incurred in connection with 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 , 2015, 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 at any time until the exchange offer expires or terminates. 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.

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,
- extend the exchange offer, or
- 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 prospectus 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 period 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 issuance of 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 prior to the expiration of the exchange offer. 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 prior to the expiration of the exchange offer.

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, as amended (the Trust Indenture Act).

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. 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 follow carefully the instructions on how to tender your old notes. 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.

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 Summary The Exchange Offer.

All of the old notes were issued in book-entry form, and all of the old notes are currently represented by global certificates registered in the name of the nominee of DTC. We have confirmed with DTC that the old notes may be tendered using the ATOP procedures. 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, as soon as practicable following the expiration date of the exchange offer.

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.

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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 as soon as practicable 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 are not participating, or intend to participate, in the distribution of the new notes;
- 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 of the exchange offer.

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.

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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 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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RATIO OF EARNINGS TO FIXED CHARGES

The table below sets forth our ratio of earnings to fixed charges for the periods indicated on a consolidated historical basis.

	For the Year Ended December 31,		
	2014	2013	2012
Ratio of earning to fixed charges(1)	x	2.1x	1.8x

(1) Earnings were inadequate to cover fixed charges by $541.4 million for the year ended December 31, 2014 primarily related to $831.1 million of compensation expense recognized in connection with our initial public offering and restructuring transactions.

For the purpose of computing the ratio of earnings to fixed charges, the term earnings is the amount resulting from adding and subtracting the following items (as applicable). Add the following: (a) pre-tax income from continuing operations before adjustment for income or loss from equity investees; (b) fixed charges; (c) amortization of capitalized interest; (d) distributed income of equity investees; and (e) your share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges. From the total of the added items, subtract the following: (a) interest capitalized; (b) preference security dividend requirements of consolidated subsidiaries; and (c) the noncontrolling interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term fixed charges means the sum of the following: (a) interest expensed and capitalized, (b) amortized premiums, discounts and capitalized expenses related to indebtedness, (c) an estimate of the interest within rental expense, and (d) preference security dividend requirements of consolidated subsidiaries.

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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 FINANCIAL DATA

The following selected financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated and combined financial statements and notes thereto included elsewhere in this prospectus.

Basis of Presentation. The selected financial data as of, and for the years ended, December 31, 2014, 2013, and 2012 presented below have been derived from our consolidated financial statements and our predecessor and the previous owners on a combined basis for periods prior to our initial public offering. For periods after the completion of our initial public offering, our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. Due to our control of MEMP through our ownership of MEMP GP, we are required to consolidate MEMP for accounting and financial reporting purposes. MEMP is owned 99.9% by its limited partners and 0.1% by MEMP GP.

Comparability of the information reflected in selected financial data. The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- the acquisition of working interests, royalty interests and net revenue interests located in the Permian Basin in July 2012 for a net purchase price of approximately $74.7 million;

- two separate third party acquisitions by MEMP of assets in East Texas in May and September 2012, respectively, for a combined net purchase price of approximately $126.9 million;

- multiple acquisitions of operated and non-operated interests in certain oil and natural gas properties primarily located in the Permian Basin during 2013 for an aggregate net purchase price of $75.9 million;

- the acquisition by WildHorse Resources of assets in Louisiana in March 2013 for approximately $67.1 million;

- the sale of assets by BlueStone in East Texas in July 2013 for approximately $117.9 million;

- the Eagle Ford Acquisition in March 2014 for a net purchase price of $168.1 million;

- the June 2014 distribution by MRD LLC of the following to MRD Holdco: (i) BlueStone, MRD Royalty, MRD Midstream, Golden Energy and Classic Pipeline; and (ii) the MEMP subordinated units;

- the contribution by certain former management members of WildHorse Resources to us of their outstanding incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources, and the issuance of 42,334,323 shares of our common stock and payment of cash consideration of $30.0 million to such former management members of WildHorse Resources and recognition of compensation expense of $831.1 million; and

the MEMP Wyoming Acquisition in July 2014 for a purchase price of approximately $906.1 million.

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As a result of the factors listed above, the consolidated and combined historical results of operations and period-to-period comparisons of these results and certain financial data may not be comparable or indicative of future results.

	For the Year Ended December 31,		
	2014	2013	2012
	(In thousands, except per share data)		
Statement of Operations Data:			
Revenues:			
Oil & natural gas sales	$ 894,967	$ 571,948	$ 393,631
Other revenues	4,378	3,075	3,237
Total revenues	899,345	575,023	396,868
Costs and expenses:			
Lease operating	161,303	113,640	103,754
Pipeline operating	2,068	1,835	2,114
Exploration	16,603	2,356	9,800
Production and ad valorem taxes	45,751	27,146	23,624
Depreciation, depletion, and amortization	314,193	184,717	138,672
Impairment of proved oil and natural gas properties	432,116	6,600	28,871
Incentive unit compensation expense	943,949	43,279	9,510
General and administrative	87,673	82,079	59,677
Accretion of asset retirement obligations	6,306	5,581	5,009
(Gain) loss on commodity derivative instruments	(749,988)	(29,294)	(34,905)
(Gain) loss on sale of properties	3,057	(85,621)	(9,761)
Other, net	(12)	649	502
Total costs and expenses	1,263,019	352,967	336,867
Operating income (loss)	(363,674)	222,056	60,001
Other income (expense):			
Interest expense, net	(133,833)	(69,250)	(33,238)
Loss on extinguishment of debt	(37,248)		
Amortization of investment premium			(194)
Other, net	(337)	145	535
Total other income (expense)	(171,418)	(69,105)	(32,897)
Income (loss) before income taxes	(535,092)	152,951	27,104
Income tax benefit (expense)	(100,971)	(1,619)	(107)
Net income (loss)	(636,063)	151,332	26,997
Net income (loss) attributable to noncontrolling interest	126,788	49,830	(2,701)

Net income (loss) attributable to Memorial Resource Development Corp.	(762,851)	101,502	29,698
Net (income) loss allocated to members	(20,305)	(90,712)	7,620
Net (income) loss allocated to previous owners	(1,425)	(10,790)	(37,318)
Net income (loss) available to common stockholders	$ (784,581)	$	$
Earnings per common share:			
Basic	$ (4.08)	n/a	n/a
Diluted	$ (4.08)	n/a	n/a
Cash Flow Data:			
Net cash flow provided by operating activities	$ 476,271	$ 277,823	$ 240,404
Net cash used in investing activities	1,816,979	367,443	606,738
Net cash provided by financing activities	1,268,945	117,950	361,761
Balance Sheet Data:			
Working capital	$ 219,580	$ 48,256	$ 63,054
Total assets	4,593,547	2,829,161	2,459,304
Total debt	2,378,413	1,663,217	939,382
Total equity	1,702,964	858,132	1,276,709

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

Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our consolidated and combined financial statements and related notes included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences are discussed in Risk Factors. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See Cautionary Statement Regarding Forward-Looking Statements in the front of this prospectus.

Overview

We are a Delaware corporation, formed by Memorial Resource Development LLC (MRD LLC) in January 2014, engaged in the acquisition, exploration, and development of natural gas and oil properties primarily in North Louisiana. MRD LLC, our accounting predecessor, was a Delaware limited liability company formed on April 27, 2011 by Natural Gas Partners VIII, L.P. (NGP VIII), Natural Gas Partners IX, L.P. (NGP IX) and NGP IX Offshore Holdings, L.P. (NGP IX Offshore) (collectively, the Funds) to own, acquire, exploit and develop oil and natural gas properties. The Funds are private equity funds managed by Natural Gas Partners (NGP).

We completed our initial public offering on June 18, 2014. In connection with the closing of our initial public offering, MRD LLC contributed to us substantially all of its assets, comprised of the following, in exchange for shares of our common stock (which were distributed to MRD LLC s sole member, MRD Holdco LLC (MRD Holdco)): (1) 100% of its ownership interests in Classic Hydrocarbons Holdings, L.P. (Classic), Classic Hydrocarbons GP Co., L.L.C. (Classic GP), Black Diamond Minerals, LLC (Black Diamond), Beta Operating Company, LLC (Beta Operating), MRD Operating LLC (MRD Operating) and Memorial Production Partners GP LLC (MEMP GP), which owns a 0.1% general partner interest and 50% of the incentive distribution rights in Memorial Production Partners LP (MEMP), and (2) its 99.9% membership interest in WildHorse Resources, LLC (WildHorse Resources). In addition, certain former management members of WildHorse Resources contributed to us the remaining 0.1% membership interest in WildHorse Resources, and also exchanged their incentive units in WildHorse Resources, for shares of our common stock and cash consideration. As a result, we are majority-owned by the group consisting of MRD Holdco and certain former management members of WildHorse Resources.

Following the completion of our initial public offering, MRD LLC distributed to MRD Holdco (i) its interests in BlueStone Natural Resources Holdings, LLC (BlueStone), MRD Royalty LLC (MRD Royalty), MRD Midstream LLC (MRD Midstream), Golden Energy Partners LLC (Golden Energy) and Classic Pipeline & Gathering, LLC (Classic Pipeline), (ii) the MEMP subordinated units (which converted to common units on February 13, 2015); (iii) the remaining cash released from its debt service reserve account in connection with the redemption of the 10.00% /10.75% Senior PIK Toggle Notes due 2018 (the PIK notes); and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy s assets in May 2014. We also reimbursed MRD LLC for the approximately $17.2 million interest payment that it made on the PIK notes on June 15, 2014, which was distributed to MRD Holdco.

As part of the restructuring transactions, we merged Black Diamond into MRD Operating in connection with the completion of our initial public offering, and MRD LLC was merged into MRD Operating upon the termination of the PIK notes indenture on June 27, 2014. WildHorse Resources merged into MRD Operating in February 2015.

On February 23, 2015, we and MEMP completed a transaction (the Property Swap) in which we exchanged certain of our oil and gas properties in East Texas and non-core Louisiana for MEMP s North

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Louisiana oil and gas properties and approximately $78.0 million in cash, subject to customary adjustments. Prior to the completion of the Property Swap, each of Classic Hydrocarbons, Inc. and Classic Operating Co. LLC were merged into Classic Hydrocarbons Operating, LLC (Classic Operating). In connection with and as part of the Property Swap, Classic sold all of the equity interests owned by it in Classic Operating, Craton Energy GP III, LLC and Craton Energy Holdings III, LP to Memorial Production Operating LLC. On March 17, 2015, Classic and Classic GP were merged into MRD Operating.

We control MEMP through the ownership of MEMP GP. MEMP is a publicly traded limited partnership engaged in the acquisition, production and development of oil and natural gas properties in the United States. Due to our control of MEMP through the ownership of MEMP GP, we are required to consolidate MEMP for accounting and financial reporting purposes. Although consolidated for accounting and financial reporting, we each have independent capital structures. We will receive cash distributions from MEMP as a result of MEMP GP s 0.1% general partner interest and incentive distribution rights in MEMP, when declared and paid by MEMP.

Business Segments

Our reportable business segments are organized in a manner that reflects how management manages those business activities. We evaluate segment performance based on Adjusted EBITDA. The definition and calculation of Adjusted EBITDA and the reconciliation of total reportable segments Adjusted EBITDA to net income (loss) is included in the notes to our consolidated and combined financial statements included elsewhere in this prospectus. Adjusted EBITDA (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in evaluating segment performance. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss). Our computation of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

We have two reportable business segments, both of which are engaged in the acquisition, exploration, development and production of oil and natural gas properties. Our reportable business segments are as follows:

- MRD-reflects the combined operations of the Company, MRD Operating, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.

- MEMP-reflects the combined operations of MEMP, its previous owners, and certain historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

Segment financial information has been retrospectively revised for the following common control transactions between MEMP and MRD LLC for comparability purposes:

- acquisition by MEMP of all the outstanding membership interests in Tanos Energy, LLC (Tanos) for a purchase price of approximately $77.4 million in October 2013;

acquisition by MEMP of all the outstanding membership interests in Prospect Energy, LLC (Prospect Energy) from Black Diamond for a purchase price of approximately $16.3 million in October 2013;

acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million in October 2013;

acquisition by MEMP of all the outstanding membership interests in WHT Energy Partners LLC (WHT) for a purchase price of approximately $200.0 million in March 2013;

acquisition by MEMP of certain assets from Classic in East Texas in May 2012 for a purchase price of approximately $27.0 million; and

acquisition by MEMP of certain assets from Tanos in East Texas in April 2012 for a purchase price of approximately $18.5 million.

The MRD Segment is focused on the acquisition, exploration, and development of natural gas and oil properties primarily in the Cotton Valley formation in North Louisiana. These properties consist primarily of assets with extensive production histories, high drilling success rates, and significant horizontal redevelopment potential. The MRD Segment is focused on maintaining and growing its production and cash flow primarily through the development of its sizeable inventory. The MRD Segment, prior to our initial public offering, included BlueStone, MRD Royalty, MRD Midstream, Golden Energy, Classic Pipeline, the MEMP subordinated units and cash held in a debt service reserve account that had been established when the PIK notes were issued in December 2013.

The MEMP Segment is engaged in the acquisition, exploitation, development and production of oil and natural gas properties, with assets consisting primarily of producing oil and natural gas properties that are located in Texas, Louisiana, Colorado, Wyoming, and New Mexico and offshore Southern California. Most of the MEMP Segment s properties are located in large, mature oil and natural gas reservoirs with well-known geologic characteristics and long-lived, predictable production profiles and modest capital requirements. The MEMP Segment is focused on generating stable cash flows to allow MEMP to make quarterly cash distributions to its unitholders and, over time, to increase those quarterly cash distributions.

Outlook

The continuation of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. Although we cannot predict the occurrence of events or factors that will affect future commodity prices, such as the supply of, and demand for, oil, natural gas, and NGLs, and general domestic or foreign economic conditions and political developments, or the degree to which these prices will be affected, the prices for any oil, natural gas or NGLs that we produce will generally approximate market prices in the geographic region of the production.

Oil prices declined significantly in the second half of 2014 and have continued to drop in early 2015. This decline in oil prices stems in large part from decreased demand due to weak economic activity and increased efficiency, an excess of supply due to sustained high output from North America, and the Organization of Petroleum Exporting Countries failure to reach agreement on production curbs in November 2014.

The U.S. Energy Information Administration, or EIA, forecasts that Brent crude oil prices will average $58 per Bbl in 2015 and $75 per Bbl in 2016. North Sea Brent crude oil spot prices averaged $62 per Bbl in December 2014, the lowest monthly average Brent price since May 2009, down $17 per Bbl from the November average. The combination of robust world crude oil supply growth and weak global demand has contributed to rising global inventories and falling crude oil prices. The EIA expects global oil inventories to continue to build in 2015, keeping downward pressure on oil prices. Like Brent crude oil prices, WTI prices have decreased considerably, with monthly average prices falling by more than 44% as of December 2014 after reaching their 2014 peak of $106 per Bbl in June. The EIA expects WTI crude oil prices to average $55 per Bbl in 2015 and $71 per Bbl in 2016.

The EIA expects the Henry Hub natural gas spot price to average $3.52 per MMBtu this winter compared with $4.51 per MMBtu last winter, reflecting both lower-than-expected space heating demand and higher natural gas production this winter. The EIA expects the Henry Hub natural gas spot price to average $3.44 per MMBtu in 2015 and $3.86 per

MMBtu in 2016, compared with $4.39 per MMBtu in 2014. The EIA expects monthly average spot prices to remain less than $4 per MMBtu until the fourth quarter of 2016.

Commodity hedging remains an important part of our strategy to reduce cash flow volatility. Our hedging activities are intended to support oil and natural gas prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. See Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk for additional information.

We expect our 2015 development program and capital budget will be focused on the Terryville Complex, where we plan to allocate approximately 100% of our drilling and completion capital budget, primarily targeting our four primary zones within the Cotton Valley the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. We expect to fund our 2015 development primarily from cash flows from operations and borrowings under our senior secured revolving credit facility. However, there can be no assurance that our operations or other capital resources will provide cash in amounts that are sufficient to maintain our planned levels of capital expenditures.

Sources of Revenues

Both our and MEMP s revenues are derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from natural gas during processing. Production revenues are derived entirely from the continental United States. Natural gas, NGL and oil prices are inherently volatile and are influenced by many factors outside our control. In order to reduce the impact of fluctuations in natural gas and oil prices on revenues, or to protect the economics of property acquisitions, both we and MEMP intend to periodically enter into derivative contracts with respect to a significant portion of estimated natural gas and oil production through various transactions that fix the future prices received. At the end of each period the fair value of these commodity derivative instruments are estimated and, because hedge accounting is not elected, the changes in the fair value of unsettled commodity derivative instruments are recognized in earnings at the end of each accounting period.

Principal Components of Cost Structure

Lease operating expenses. These are the day to day costs incurred to maintain production of our natural gas, NGLs and oil. Such costs include utilities, direct labor, water injection and disposal, materials and supplies, compression, repairs and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services.

Production and ad valorem taxes. These consist of severance and ad valorem taxes. Production taxes are paid on produced natural gas, NGLs and oil based on a percentage of market prices and at fixed per unit rates established by federal, state or local taxing authorities. Both we and MEMP take full advantage of all credits and exemptions in the various taxing jurisdictions where we operate. Ad valorem taxes are generally tied to the valuation of the oil and natural properties; however, these valuations are reasonably correlated to revenues, excluding the effects of any commodity derivative contracts.

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

Impairment of proved properties. Proved properties are impaired whenever the carrying value of the properties exceed their estimated undiscounted future cash flows.

Depreciation, depletion and amortization. Depreciation, depletion and amortization, or DD&A, includes the systematic expensing of the capitalized costs incurred to acquire, exploit and develop natural gas and oil properties. As a successful efforts company, all costs associated with acquisition and development efforts and all successful exploration efforts are capitalized, and these costs are depleted using the units of production method.

Incentive unit compensation expense. For more information regarding compensation expense recognized associated with incentive units, see Note 12 to our consolidated and combined financial statements included elsewhere in this prospectus.

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General and administrative expense. These costs include overhead, including payroll and benefits for employees, costs of maintaining headquarters, costs of managing production and development operations, compensation expense associated with certain long-term incentive-based plans, franchise taxes, audit and other professional fees, and legal compliance expenses.

Interest expense. We and MEMP finance a portion of our working capital requirements and acquisitions with borrowings under revolving credit facilities and senior note issuances. As a result, we and MEMP incur substantial interest expense that is affected by both fluctuations in interest rates and financing decisions. We expect to continue to incur significant interest expense as we continue to grow.

Income tax expense. Prior to our initial public offering, MRD LLC was organized as a pass-through entity for federal income tax purposes and was not subject to federal income taxes; however, certain of its consolidating subsidiaries were taxed as corporations and subject to federal income taxes. We are organized as a taxable C corporation and subject to federal and certain state income taxes. We are also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable margin apportioned to operations in Texas.

Results of Operations

MRD Segment

The MRD Segment s consolidated and combined results of operations for the years ended December 31, 2014, 2013 and 2012 presented below have been derived from our predecessor s and our consolidated and combined financial statements. The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

the sale of assets by BlueStone in East Texas in July 2013 for approximately $117.9 million;

the acquisition by WildHorse Resources of assets in Louisiana in March 2013 for approximately $67.1 million; and

the distribution by MRD LLC of the following to MRD Holdco: (i) BlueStone, which sold substantially all of its assets in July 2013 for $117.9 million, MRD Royalty, which owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana, MRD Midstream, which owns an indirect interest in certain midstream assets in North Louisiana, Golden Energy and Classic Pipeline and (ii) 5,360,912 subordinated units of MEMP (which converted to common units on February 13, 2015).

Segment financial information has been retrospectively revised for material common control transactions between MEMP and MRD LLC for comparability purposes, which includes the following transactions:

acquisition by MEMP of all the outstanding membership interests in Tanos for a purchase price of approximately $77.4 million in October 2013;

acquisition by MEMP of all the outstanding membership interests in Prospect Energy from Black Diamond for a purchase price of approximately $16.3 million in October 2013;

acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million in October 2013;

acquisition by MEMP of all the outstanding membership interests in WHT for a purchase price of approximately $200.0 million in March 2013;

acquisition by MEMP of certain assets from Classic in East Texas in May 2012 for a purchase price of approximately $27.0 million; and

acquisition by MEMP of certain assets from Tanos in East Texas in April 2012 for a purchase price of approximately $18.5 million.

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	For the Year Ended December 31, 2014	2013	2012
	(in thousands)		
Oil & natural gas sales	$ 404,718	$ 230,751	$ 138,032
Lease operating	26,695	25,006	24,438
Exploration	15,813	1,226	7,337
Production and ad valorem taxes	14,150	9,362	7,576
Depreciation, depletion, and amortization	154,917	87,043	62,636
Impairment of proved oil and natural gas properties	24,576	2,527	18,339
Incentive unit compensation expense	943,949	43,279	9,510
General and administrative	42,054	38,479	28,904
(Gain) loss on commodity derivative instruments	(257,734)	(3,013)	(13,488)
(Gain) loss on sale of properties	3,057	(82,773)	(2)
Interest expense, net	(50,283)	(27,349)	(12,802)
Loss on extinguishment of debt	(37,248)		
Income tax benefit (expense)	(99,850)	(1,311)	178
Net income (loss)	(762,926)	82,243	(14,641)
Natural gas and oil revenue:			
Oil sales	$ 85,150	$ 66,961	$ 35,264
NGL sales	85,730	53,881	36,611
Natural gas sales	233,838	109,909	66,157
Total natural gas and oil revenue	$ 404,718	$ 230,751	$ 138,032
Production Volumes:			
Oil (MBbls)	951	665	369
NGLs (MBbls)	2,220	1,457	898
Natural gas (MMcf)	63,801	34,092	24,130
Total (MMcfe)	82,815	46,819	31,731
Average net production (MMcfe/d)	226.9	128.3	86.7
Average sales price:			
Oil (per Bbl)	$ 89.54	$ 100.76	$ 95.56
NGL (per Bbl)	38.62	36.99	40.78
Natural gas (per Mcf)	3.67	3.22	2.74
Total (Mcfe)	$ 4.89	$ 4.93	$ 4.35
Average unit costs per Mcfe:			
Lease operating expense	$ 0.32	$ 0.53	$ 0.77
Production and ad valorem taxes	$ 0.17	$ 0.20	$ 0.24
General and administrative expenses	$ 0.51	$ 0.82	$ 0.91
Depletion, depreciation, and amortization	$ 1.87	$ 1.86	$ 1.97

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

The MRD Segment recorded a net loss of $762.9 million during 2014 compared to net income of $82.2 million during 2013. The net loss recorded during 2014 was primarily due to compensation expense associated with incentive units as discussed below.

Oil and natural gas revenues for 2014 totaled $404.7 million, an increase of $174.0 million compared with 2013. Production increased 36.0 Bcfe (approximately 77%) primarily due to drilling activities in North Louisiana. The average realized sales price decreased $0.04 per Mcfe primarily due to lower oil prices. The favorable volume variance contributed to an approximate $177.5 million increase and was offset by $3.5 million due to the unfavorable pricing variances.

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Lease operating expenses were $26.7 million and $25.0 million for 2014 and 2013, respectively. On a per Mcfe basis, lease operating expenses decreased to $0.32 for 2014 from $0.53 for 2013. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges.

DD&A expense for 2014 was $154.9 million compared to $87.0 million for 2013, a $67.9 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to drilling activities in North Louisiana. Increased production volumes caused DD&A expense to increase by an approximate $67.1 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $0.8 million.

Impairment expense for 2014 was $24.6 million compared to $2.5 million for 2013. The impairments primarily related to certain properties located in the Rockies and certain fields in North Louisiana. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable primarily due to a decline in prices.

Incentive unit compensation expense for 2014 was $943.9 million, of which $831.1 million related to WildHorse Resources incentive units, $111.8 million related to MRD Holdco incentive units, and $1.0 million related to BlueStone incentive units. We recognized $43.3 million of compensation expense associated with long-term incentive plans for 2013. Incentive unit compensation expense of approximately $20.7 million was recorded by BlueStone, $10.0 million related to WildHorse Resources and $12.6 million related to the Classic and Black Diamond management buyouts in 2013. Net proceeds generated from the sale of oil and gas properties were used to pay a distribution to BlueStone incentive unit holders.

General and administrative expenses for 2014 were $42.1 million compared to $38.5 million for 2013. General and administrative expenses for 2014 included $2.3 million of acquisition-related costs. General and administrative expenses for 2013 included $1.6 million of acquisition-related costs. Increased salaries and employee headcount also contributed to increased general and administrative expenses between periods.

Net gains on commodity derivative instruments of $257.7 million were recognized during 2014, consisting of $9.2 million of cash settlement receipts in addition to a $248.5 million increase in the fair value of open hedge positions. Net gains on commodity derivative instruments of $3.0 million were recognized during 2013, consisting of $12.2 million of cash settlement receipts offset by a $9.2 million decrease in the fair value of open hedge positions.

Net interest expense during 2014 was $50.3 million, including amortization of deferred financing fees of approximately $3.2 million. Net interest expense during 2013 was $27.3 million, including amortization of deferred financing fees of approximately $2.5 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including the old notes and the PIK notes.

Average outstanding borrowings under our senior secured revolving credit facility were $111.1 million during 2014. Average outstanding borrowings under the previous owners revolving credit facilities were $282.6 million during

2013. For the year ended December 31, 2014, we had an average of $634.5 million aggregate principal amount of the old notes, PIK notes and WildHorse Resources second lien term facility issued and outstanding. For the year ended December 31, 2013, we had an average of $13.4 million aggregate principal amount of the PIK notes issued and outstanding and an average of $179.9 million aggregate principal outstanding for the WildHorse Resources second lien term facility.

During 2014, we sold certain producing and non-producing properties in the Mississippian oil play in Northern Oklahoma to a third party and recorded a loss of $3.2 million. During 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties and recognized a gain of $89.5 million. This gain was offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain oil and gas properties.

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An extinguishment loss of $23.6 million was recognized related to the redemption of the PIK notes. In connection with the closing of our initial public offering, WildHorse Resources revolving credit facility and second lien term loan were repaid in full and terminated. An extinguishment loss of $13.7 million was recognized related to the termination of the revolving credit facility and second lien term loan.

We are organized as a taxable C corporation and subject to federal and certain state income taxes. We recorded tax expense of $99.9 million in 2014 subsequent to our initial public offering. Taxes recognized in 2014 related primarily to deferred items such as hedging gains and oil and natural gas property temporary differences. Prior to our initial public offering we were a flow through entity.

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

The MRD Segment recorded net income of $82.2 million in 2013 compared to a net loss of $14.6 million in 2012. The increase in net income was primarily due to gains on sales of properties and increased production.

Oil and natural gas revenues were $230.8 million in 2013, an increase of $92.7 million from 2012. Production increased 15.1 Bcfe (approximately 48%) while the average realized sales price increased $0.58 per Mcfe. Production volume increases were primarily due to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. The favorable volume variance contributed to a $65.6 million increase in revenues, and the favorable pricing variance contributed to a $27.1 million increase in revenues.

Lease operating expenses were $25.0 million in 2013, an increase in $0.6 million from 2012. This increase was primarily due to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. However, on a per Mcfe basis, lease operating expenses decreased by $0.24 per Mcfe as certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges.

The $24.4 million increase in DD&A expense was primarily due to increased production volumes related to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. Increased production volumes increased DD&A expense by $29.8 million, while a 6% decrease in the DD&A rate between periods decreased DD&A expense by $5.4 million. On a per Mcfe basis, DD&A expense decreased by $0.11 per Mcfe from 2012 to 2013. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base.

During 2013 and 2012, the MRD Segment recorded impairments of $2.5 million and $18.3 million, respectively, primarily related to certain fields in East Texas. For these impairments, the estimated future cash flows expected from properties in these fields were compared to their carrying values and determined to be unrecoverable. Downward revisions due to performance and declines in natural gas prices triggered the 2013 and 2012 impairments, respectively.

Incentive unit compensation expense for 2013 was $43.3 million as discussed above, which related to incentive unit payments to certain key management members of certain MRD LLC subsidiaries compared to approximately $9.5 million recorded in 2012.

General and administrative expenses were $38.5 million in 2013, an increase of $9.6 million from 2012. The increase in general and administrative expenses was primarily due to growth in employees as a result of acquisitions and development activities.

Gains on commodity derivative instruments of $3.0 million were recognized during 2013, of which $12.2 million consisted of cash settlements received. Gains on commodity derivative instruments of $13.5 million were recognized during 2012, of which $30.2 million consisted of cash settlements received. The decrease in cash settlements received was primarily due to higher natural gas prices.

During 2013, BlueStone entered into an agreement with a publicly traded third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties

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located in East Texas and recognized a gain of $89.5 million. This gain was offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain of its Wyoming oil and gas properties. During 2012, gains of less than $0.1 million were recognized by the MRD Segment.

Net interest expense during 2013 was $27.3 million, including amortization of deferred financing fees of approximately $2.5 million and losses on interest rate swaps of $0.2 million. Net interest expense during 2012 was $12.8 million, including amortization of deferred financing fees of approximately $1.6 million and losses on interest rate swaps of $1.2 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2013 compared to 2012. Average debt outstanding was $475.9 million and $272.6 million for 2013 and 2012, respectively.

MEMP Segment

The MEMP Segment s consolidated and combined results of operations for the years ended December 31, 2014, 2013 and 2012 presented below have been derived from our consolidated and combined financial statements included elsewhere in this prospectus.

The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- two separate third party acquisitions by MEMP of assets in East Texas in May and September 2012, respectively, for a combined net purchase price of approximately $126.9 million;
- third party acquisition of working interests, royalty interests and net revenue interests located in the Permian Basin in July 2012 for a net purchase price of approximately $74.7 million;
- the 2012 divestiture of the offshore Louisiana properties by MEMP s previous owners to a related party;
- multiple third party acquisitions of operated and non-operated interests in certain oil and natural gas properties primarily located in the Permian Basin for an aggregate net purchase price of $75.9 million during 2013;
- the Eagle Ford Acquisition in March 2014 for a net purchase price of $168.1 million; and
- the MEMP Wyoming Acquisition in July 2014 for a purchase price of approximately $906.1 million.

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	For the Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Oil & natural gas sales	$ 490,249	$ 341,197	$ 255,608
Lease operating	134,654	88,893	80,116
Exploration	790	1,130	2,463
Production and ad valorem taxes	31,601	17,784	16,048
Depreciation, depletion, and amortization	155,404	97,269	76,036
Impairment of proved oil and natural gas properties	407,540	54,362	10,532
General and administrative	45,619	43,495	30,342
(Gain) loss on commodity derivative instruments	(492,254)	(26,281)	(21,417)
(Gain) loss on sale of properties		(2,848)	(9,759)
Interest expense, net	(83,550)	(41,901)	(20,436)
Net income (loss)	118,079	20,268	46,518
Natural gas and oil revenue:			
Oil sales	$ 262,407	$ 171,095	$ 145,103
NGL sales	64,718	51,215	26,647
Natural gas sales	163,124	118,887	83,858
Total natural gas and oil revenue	$ 490,249	$ 341,197	$ 255,608
Production Volumes:			
Oil (MBbls)	3,092	1,764	1,519
NGLs (MBbls)	2,143	1,632	745
Natural gas (MMcf)	41,494	35,924	29,744
Total (MMcfe)	72,902	56,303	43,329
Average net production (MMcfe/d)	199.7	154.3	118.4
Average sales price:			
Oil (per Bbl)	$ 84.88	$ 96.98	$ 95.54
NGL(per Bbl)	30.20	31.38	35.75
Natural gas (per Mcf)	3.93	3.31	2.82
Total (Mcfe)	$ 6.72	$ 6.06	$ 5.90
Average unit costs per Mcfe:			
Lease operating expense	$ 1.85	$ 1.58	$ 1.85
Production and ad valorem taxes	$ 0.43	$ 0.32	$ 0.37
General and administrative expenses	$ 0.63	$ 0.77	$ 0.70
Depletion, depreciation, and amortization	$ 2.13	$ 1.73	$ 1.75

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Net income of $118.1 million was generated for the year ended December 31, 2014, primarily due to gains on commodity derivatives offset by impairment charges. Net income of $20.3 million was generated for the year ended December 31, 2013.

Oil and natural gas sales for 2014 totaled $490.2 million, an increase of $149.1 million compared with 2013. Production increased 16.6 Bcfe (approximately 29%), primarily from volumes associated with third party acquisitions. The average realized sales price increased $0.66 per Mcfe primarily due to higher gas prices and an increase in oil volumes relative to other commodities due to MEMP s acquisitions. The favorable volume and pricing variance contributed to an approximate $100.5 million and $48.6 million increase in revenues, respectively.

Lease operating expenses were $134.7 million and $88.9 million for the year ended December 31, 2014 and 2013, respectively. In the MEMP Wyoming Acquisition, MEMP acquired more oil weighted properties, which are generally more expensive to operate compared to natural gas properties (on a per Mcfe basis). On a per Mcfe basis, lease operating expenses increased to $1.85 for 2014 from $1.58 for 2013.

Production and ad valorem taxes for 2014 totaled $31.6 million, an increase of $13.8 million compared with 2013 primarily due to an increase in production volumes and ad valorem tax rates. On a per Mcfe basis, production and ad valorem taxes increased to $0.43 for 2014 from $0.32 for 2013 due to higher production tax rates on a per Mcfe basis for MEMP s Wyoming Acquisition.

DD&A expense for 2014 was $155.4 million compared to $97.3 million for 2013, a $58.1 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to third party acquisitions and MEMP s drilling program. Increased production volumes caused DD&A expense to increase by an approximate $28.7 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $29.4 million.

MEMP recognized $407.5 million of impairments in 2014 related primarily to certain properties in the Permian Basin, East Texas, and South Texas. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves as a result of declining commodity prices and updated well performance data. During 2013, MEMP recorded $54.4 million of impairments consisting of $50.3 million related to certain properties in East Texas and $4.1 million related to certain properties in South Texas. For the East Texas properties, the estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on updated well performance data. In South Texas, the estimated future cash flows expected these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on pricing terms specific to these properties.

In 2013, there was a $50.3 million impairment elimination as certain fields in East Texas noted above were not impaired on a consolidated basis.

General and administrative expenses for 2014 were $45.6 million and included $7.9 million of non-cash unit-based compensation expense and $4.4 million of acquisition-related costs. General and administrative expenses for 2013 totaled $43.5 million and included $3.6 million of non-cash unit-based compensation expense and $6.7 million of acquisition-related costs. The $2.1 million increase in general administrative expenses consisted of increased salaries and employee count between periods offset by $5.8 million of one-time compensation expense related to the Tanos management buyout during 2013.

Net gains on commodity derivative instruments of $492.3 million were recognized during 2014, consisting of $13.6 million of cash settlement receipts in addition to a $478.7 million increase in the fair value of open hedge positions. Net gains on commodity derivative instruments of $26.3 million were recognized during 2013, consisting of $19.9 million of cash settlement receipts, in addition to a $6.4 million increase in the fair value of open hedge positions.

Net interest expense is comprised of interest on credit facilities, interest on MEMP s outstanding senior notes, amortization of debt issue costs, accretion of net discount associated with the senior notes and gains and losses on interest rate swaps. Net interest expense totaled $83.6 million during 2014, including amortization of deferred financing fees of approximately $4.2 million and accretion of net discount associated with the senior notes of $1.9 million. Net interest expense totaled $41.9 million during 2013, including gains on interest rate swaps of $1.5 million and amortization of deferred financing fees of approximately $5.8 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including MEMP s 2022 Senior Notes.

Average outstanding borrowings under MEMP s revolving credit facility were $413.6 million during 2014 compared to $184.7 million during 2013. Average outstanding borrowings under the previous owners

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revolving credit facilities were $21.3 million during 2013. For the year ended December 31, 2014, MEMP had an average of $950.7 million aggregate principal amount of MEMP s senior notes issued and outstanding. For the year ended December 31, 2013, MEMP had an average of $342.2 million aggregate principal amount of MEMP s senior notes issued and outstanding.

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

MEMP recorded net income of $20.3 million in 2013 compared to income of $46.5 million in 2012.

Oil and natural gas sales were $341.2 million in 2013, an increase of $85.6 million from 2012. Production increased 13.0 Bcfe (approximately 30%) while the average realized sales price increased $0.16 per Mcfe. The favorable volume variance contributed to a $76.6 million increase in revenues, whereas the favorable pricing variance contributed to a $9.0 million decrease in revenues.

Lease operating expenses were $88.9 million in 2013, an increase of $8.8 million from 2012. Production and ad valorem taxes were $17.8 million in 2013, an increase of $1.8 million from 2012. Both lease operating expenses and production and ad valorem taxes increased primarily due to increased production volumes associated with properties acquired during both 2012 and 2013 and increased drilling activities.

The increase in DD&A expense was primarily due to increased production volumes related to acquisitions in 2012 and 2013 and increased drilling activities. Increased production volumes caused DD&A expense to increase by $22.8 million, while a 1% change in the DD&A rate between periods caused DD&A expense to decrease by $1.5 million. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base.

During 2013, MEMP recorded $54.4 million of impairments consisting of $50.3 million related to certain properties in East Texas and $4.1 million related to certain properties in South Texas. For the East Texas properties, the estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of downward revisions of estimated proved reserves based upon updated well performance data. In South Texas, the estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on pricing terms specific to these properties. During 2012, MEMP recorded impairments of $10.5 million primarily related to properties in the Permian Basin. The 2012 impairments were a result of downward revisions of estimated proved reserves due to unfavorable drilling results in the area.

In 2013, there was a $50.3 million impairment elimination as certain fields in East Texas noted above were not impaired on a consolidated basis.

General and administrative expenses were $43.5 million in 2013, an increase of $13.2 million. The increase in general and administrative expenses was primarily due to growth in employees as a result of acquisitions and drilling activities. General and administrative expenses for 2013 included $3.6 million of non-cash unit-based compensation expense and $6.7 million of acquisition-related costs. General and administrative expenses for 2012 were $30.3 million and included $1.4 million of non-cash unit-based compensation expense and $4.1 million of acquisition-related costs.

Net gains on commodity derivative instruments of $26.3 million were recognized during 2013, of which $19.9 million consisted of cash settlements. Net gains on commodity derivative instruments of $21.4 million were recognized during 2012, of which $44.1 million consisted of cash settlements. The decrease in cash settlements was primarily due to higher natural gas prices.

During 2013, a gain of approximately $2.8 million was recorded due to the sale of certain non-operated properties in East Texas. During 2012, a gain of approximately $9.8 million was recognized related to the sale of properties in Garza and Ector Counties in Texas.

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Net interest expense during 2013 was $41.9 million, including amortization of deferred financing fees of approximately $5.8 million and gains on interest rate swaps of $1.5 million. Net interest expense during 2012 was $20.4 million, including amortization of deferred financing fees of approximately $0.6 million and losses on interest rate swaps of $4.0 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2013 compared to 2012.

Consolidated

For consolidated results of operations, see MRD Segment and MEMP Segment above.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, the MRD and MEMP Segments operate with independent capital structures. The MEMP Segment s debt is nonrecourse to the Company. With the exception of cash distributions paid to the MRD Segment by the MEMP Segment related to MEMP partnership interests held by the Company the cash needs of each segment have been met independently with a combination of operating cash flows, asset sales, credit facility borrowings and the issuance of debt and equity. We expect that the cash needs of each of the MRD Segment and the MEMP Segment will continue to be met independently of each other with a combination of these funding sources.

MRD Segment

Historically, the primary sources of liquidity have been through borrowings under credit facilities, capital contributions from NGP and certain members of management, borrowings under a second lien term loan facility, issuance of senior notes, asset sales, including dropdowns to MEMP, and net cash provided by operating activities. The primary use of cash has been for the exploration, development and acquisition of natural gas and oil properties. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet future financial obligations, planned capital expenditure activities and liquidity requirements. Any future success in growing proved reserves and production will be highly dependent on the capital resources available.

Currently, the primary sources of liquidity and capital resources are cash flows generated by operating activities and borrowings under our senior secured revolving credit facility. We also have the ability to issue additional equity and debt as needed through both private and public offerings. We may from time to time refinance our existing indebtedness including by issuing longer-term fixed rate debt to refinance shorter-term floating rate debt.

Based on our current oil and natural gas price expectations, we believe our cash flows provided by operating activities and availability under our senior secured revolving credit facility will provide us with the financial flexibility and wherewithal to meet our cash requirements, including normal operating needs, and pursue our currently planned 2015 development drilling activities. However, future cash flows are subject to a number of variables, including the level of our oil and natural gas production and the prices we receive for our oil and natural gas production, and significant additional capital expenditures will be required to more fully develop our properties and acquire additional properties. We cannot assure you that operations and other needed capital will be available on acceptable terms, or at all.

As of December 31, 2014, our liquidity of $547.0 million consisted of $5.0 million of cash and cash equivalents and $542.0 million of available borrowings under our senior secured revolving credit facility. As of December 31, 2014, we had a working capital balance of $65.2 million. As of December 31, 2014, the borrowing base under our senior secured revolving credit facility was $725.0 million and we had $183.0 million of outstanding borrowings. The borrowing base under our senior secured revolving credit facility is subject to redetermination on at least a semi-annual basis based on an engineering report with respect to our estimated oil and natural gas reserves, which will take into account the prevailing oil and natural gas prices at such time, as adjusted for the impact of our commodity derivative contracts. Unanimous approval by the lenders is required for any increase to the borrowing base. The borrowing base was reaffirmed at $725 million on April 13, 2015 and the next semi-annual borrowing base redetermination is scheduled for October 2015. A continuing decline in oil and natural gas prices or a prolonged period of lower oil and natural gas prices could result in a reduction of our borrowing base under our senior secured revolving credit facility and could trigger mandatory principal repayments.

Capital Budget

The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. If oil and natural gas prices decline below levels we deem acceptable, we may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside of our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and labor crews.

Capital expenditures totaled $517.5 million for the year ended December 31, 2014 and included $97.8 million related to acquisitions. In 2014, MRD spent approximately 90% of its capital expenditures in the Terryville Complex and Other North Louisiana, 5% in East Texas and 5% in the Rockies. Our current estimated drilling and completion capital expenditure budget for 2015 is $475.0 million to $525.0 million, with substantially all capital expenditures dedicated to the Terryville Complex.

Cash Flows from Operating, Investing and Financing Activities

The following tables summarize segment cash flows from operating, investing and financing activities for the periods indicated. For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated and Combined Cash Flows in our consolidated and combined financial statements included elsewhere in this prospectus.

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MRD Segment

	For Year Ended December 31, 2014	2013	2012
Net cash provided by operating activities	$ 251,370	$ 83,910	$ 84,172
Net cash provided by (used in) investing activities:			
Acquisition of oil and natural gas properties	$ (93,909)	$ (67,098)	$ (83,055)
Additions to oil and gas properties	(410,151)	(198,340)	(165,203)
Additions to other property and equipment	(16,978)	(2,432)	(1,268)
Equity investments in MEMP Segment	(570)	(521)	(206)
Distributions received from MEMP Segment related to partnership interests	6,144	26,006	19,263
Decrease (increase) in restricted cash	49,946	(49,347)	
Proceeds from the sale of oil and gas properties to third parties	6,700	151,187	
Proceeds from the sale of MEMP common units		135,012	
Other	(516)		(2)
Net cash provided by (used in) investing activities	$ (459,334)	$ (5,533)	$ (230,471)
Net cash provided by (used in) financing activities			
Advances on revolving credit facilities	$ 1,300,800	$ 174,400	$ 228,450
Payments on revolving credit facilities	(1,320,900)	(280,500)	(129,750)
Proceeds from issuance of senior notes	600,000	343,000	
Redemption of senior notes	(351,808)		
Borrowings under second lien credit facility		325,000	
Redemption of second lien credit facility	(328,282)		
Deferred financing costs	(18,840)	(20,267)	(1,276)
Purchase of additional interests in consolidated subsidiaries	(3,292)	(13,865)	
Net proceeds from initial public offering	380,127		
Repurchased shares under repurchase program	(161)		
Contribution from NGP affiliates related to sale of properties	1,165		7,033
Contributions from MEMP Segment	48,880	180,260	29,280
Distributions to Funds		(732,362)	
Distributions to MRD Holdco	(59,803)		
Distributions to noncontrolling interest	(325)	(7,446)	
Distributions to MEMP Segment			(1,900)
Distribution to NGP affiliates related to purchase of assets	(66,693)		
Distribution to NGP affiliates related to sale of assets, net of cash received	(32,770)		
Distributions made by previous owners		(2,590)	(2,317)
Other cash transfers from MEMP Segment			3,751
Other	269	(4,593)	

Net cash provided by (used in) financing activities	$ 148,367	$ (38,963)	$ 133,271

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Operating Activities. Net cash flows provided by operating activities were $251.4 million during 2014 compared to $83.9 million during 2013. Production increased 36.0 Bcfe (approximately 77%) and average realized sales price decreased $0.04 per Mcfe as previously discussed above under Results of Operations MRD Segment. Cash paid for interest during 2014 was $67.0 million compared to $61.1 million during 2013. During 2014, compensation expense of approximately $26.7 million was paid in cash related to WildHorse Resources incentive units compared to $43.3 million in 2013 related to incentive units.

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Investing Activities. Total cash used in investing activities was $459.3 million during 2014 compared to $5.5 million during 2013. Cash used for the acquisition of oil and gas properties was $93.9 million during 2014 compared to $67.1 million used in 2013. The 2014 and 2013 acquisitions were for certain properties located in Louisiana. Cash used for additions to oil and gas properties was $410.2 million during 2014 compared to $198.3 million during 2013, which consisted primarily of drilling and completion activities in the Cotton Valley in North Louisiana and East Texas area. Additions to other property and equipment were $17.0 million which consisted primarily of computer hardware, software, and other leased office space build out during 2014. Distributions of $6.1 million were received from MEMP primarily from the subordinated units owned by MRD LLC through June 18, 2014 compared to $26.0 million during 2013 received from MEMP primarily from the common and subordinated units then owned by MRD LLC. In May 2014, Black Diamond sold certain producing and non-producing properties in the Mississippian oil play of Northern Oklahoma to a third party for cash consideration of approximately $6.7 million. On July 31, 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East Texas. Total cash consideration received by BlueStone was approximately $117.9 million. On June 4, 2013, Black Diamond sold certain of its Wyoming oil and gas properties to a third party for cash consideration of approximately $32.9 million. In 2014, there was a decrease in restricted cash of $49.9 million, which was primarily due to $50.0 million being released from the debt service reserve account associated with the PIK notes. In November 2013, MRD LLC sold 7,061,294 MEMP common units in a secondary public offering, which generated net proceeds of $135.0 million.

Financing Activities. On June 18, 2014, we completed our initial public offering pursuant to which we sold 21,500,000 shares of our common stock to the public at an offering price of $19.00 per share. Net proceeds from our initial public offering were $380.1 million. We used approximately $360.0 million of our initial public offering proceeds to redeem the PIK notes on June 27, 2014, of which $351.8 million was classified as a financing activity and the remaining $8.2 million was classified as an operating activity representing interest expense.

Net repayments under revolving credit facilities were $20.1 million during 2014 compared to net repayments of $106.1 million during 2013. Amounts borrowed under our senior secured revolving credit facility were primarily incurred to repay the amounts outstanding under WildHorse Resources credit facilities in connection with the closing of our initial public offering. WildHorse Resources primarily utilized its revolving credit facility during 2014 to repurchase net profits interests from an affiliate of NGP. On June 13, 2013, WildHorse Resources borrowed $325.0 million under its second lien term loan agreement and used such borrowings to reduce outstanding indebtedness under its revolving credit facility and to pay a one-time special $225.0 million distribution to MRD LLC, which MRD LLC subsequently distributed to the Funds. In connection with the closing of our initial public offering, WildHorse Resources second lien term loan was repaid in full, including a premium of approximately $3.3 million.

Net proceeds of $586.8 million from the issuance of the old notes during the year ending December 31, 2014 were used to repay portions of our borrowings outstanding under our senior secured revolving credit facility.

Distributions to NGP affiliates related to the purchase of assets were primarily related to WildHorse Resources February 2014 acquisition of net profits interests in the Terryville Complex from an affiliate of NGP for $63.4 million. MRD Royalty also acquired certain interests in oil and gas properties in Gonzales and Karnes Counties located in South Texas from an affiliate of NGP for $3.3 million in March 2014. Distributions to NGP affiliates related to the sale of assets were $32.8 million. WildHorse Resources sold its subsidiary, WHR Management Company, to an affiliate of the Funds for approximately $0.2 million and $33.0 million of cash was a component of the net book value transferred. For additional information regarding this transaction, see Note 13 to our consolidated and combined financial statements included elsewhere in this prospectus.

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MEMP paid $33.9 million to WildHorse Resources in connection with MEMP s April 2014 acquisition of certain oil and natural gas properties in East Texas. MEMP paid $15.0 million to MRD in connection with MEMP s acquisition of certain oil and gas properties in the Rockies in October 2014. MEMP paid $55.4 million to WildHorse Resources in connection with MEMP s March 2013 acquisition of all the outstanding equity interests in WHT. MEMP paid $96.4 million to MRD LLC related to acquisitions of certain oil and natural gas properties in October 2013. Tanos also distributed approximately $20.9 million to MRD LLC during 2013.

In connection with our initial public offering, certain former management members of WildHorse Resources contributed their 0.1% membership interest and incentive units in WildHorse Resources in exchange for 42,334,323 shares of our common stock and cash consideration of $30.0 million. The portion of the total consideration related to acquiring the 0.1% membership interest was $3.3 million. In November 2013, MRD LLC purchased noncontrolling interests in Black Diamond, Classic GP and Classic for $13.9 million in cash.

Distributions to MRD Holdco during 2014 were $59.8 million. Approximately $6.7 million of cash received by MRD LLC in connection with the sale of assets in May 2014 was distributed to MRD Holdco in connection with our initial public offering. We also reimbursed MRD LLC for the approximately $17.2 million interest payment that it made on the PIK notes on June 15, 2014, which was distributed to MRD Holdco. Remaining cash of $32.8 million released from the debt service reserve account in connection with the redemption and discharge of the PIK notes was also distributed to MRD Holdco.

Distributions to the Funds during 2013 were $732.4 million. From time to time, MRD LLC made distributions of cash to the Funds. The timing and amount of these cash distributions was within the discretion of the board of managers of MRD LLC and was based, in part, upon available cash, the performance of its business, and other relevant factors. In 2013, substantially all of the cash distributed to the Funds was sourced from long term borrowings or sales of assets or equity in MEMP. The sources to fund these distributions primarily included $225.0 million from the WildHorse second lien term loan, $210.0 million from the December 2013 PIK notes, $63.8 million from the sale of properties to third parties, $125.0 million from the sale of properties to MEMP and $105.0 million from the sale of 7,061,294 MEMP common units that MRD LLC owned. Distributions to noncontrolling interests and previous owners totaled $10.0 million in 2013. Deferred financing costs of approximately $18.8 million were incurred during 2014 compared to approximately $20.3 million during 2013.

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

Operating Activities. Net cash flows provided by operating activities were $83.9 million in 2013 compared to $84.2 million in 2012. Although production volumes increased 15.1 Bcfe (approximately 48%), net cash flows from operating activities were impacted by $43.3 million of compensation expense recognized in 2013 related to incentive unit payments, which was an increase of $33.8 million from 2012.

Investing Activities. Cash used in investing activities was $5.5 million during 2013 compared to $230.5 million in 2012. Cash used for the acquisition of oil and gas properties was $67.1 million in 2013 compared to $83.1 million in 2012. The 2013 acquisition was for certain properties located in Louisiana that were purchased in March 2013. The 2012 acquisitions consisted primarily of properties located in East Texas and North Louisiana.

Cash used for additions to oil and gas properties was $198.3 million in 2013 compared to $165.2 million in 2012. The additions in both 2013 and 2012 consisted primarily of drilling and completion activities focused on the Cotton Valley formation in North Louisiana and East Texas.

Distributions of $26.0 million were received in 2013 from MEMP related to the common and subordinated units owned by MRD LLC as compared to $19.3 million received in 2012. In November 2013, MRD LLC sold 7,061,294 MEMP common units in a public offering, which generated net proceeds of $135.0 million.

Proceeds from the sale of oil and gas properties totaled $151.2 million in 2013. In May 2013, Black Diamond sold certain of its Wyoming properties for approximately $33.0 million. In July 2013, BlueStone sold its interest in certain properties located in Walker and Madison Counties in East Texas for approximately $117.9 million. There were no sales of oil and gas properties in 2012.

Additions to restricted cash totaled $49.3 million and were primarily related to the $50.0 million debt service reserve established in connection with the issuance of the PIK notes in December 2013.

Financing Activities. Cash used in financing activities was $39.0 million in 2013 compared to cash provided by financing activities of $133.3 million in 2012. Net payments under revolving credit facilities were $106.1 million in 2013 compared to net borrowings of $98.7 million in 2012. In June 2013, WildHorse Resources received gross proceeds of $325.0 million under its second lien term loan and in December 2013, MRD LLC received gross proceeds of $343.0 million related to the issuance of the PIK notes. Deferred financing costs were $20.3 million in 2013 compared to $1.3 million in 2012. The increase in deferred financing costs was primarily due to the WildHorse second lien term loan and the PIK notes.

In November 2013, MRD LLC purchased the noncontrolling interests in Black Diamond, Classic GP and Classic for $13.9 million of aggregate consideration.

Cash received from the MEMP Segment in 2013 related to the sale of assets from the MRD Segment to the MEMP Segment was $180.3 million compared to $29.3 million.

Distributions to the Funds during 2013 were $732.4 million as discussed above. Distributions to noncontrolling interests and previous owners totaled $10.0 million in 2013 compared to $2.3 million in 2012.

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MEMP Segment

	For Year Ended December 31,		
	2014	2013	2012
Net cash provided by operating activities	$ 224,898	$ 193,697	$ 156,844
Net cash provided by (used in) investing activities:			
Acquisition of oil and natural gas properties	$ (1,083,761)	$ (38,664)	$ (277,623)
Additions to oil and gas properties	(264,245)	(161,675)	(107,789)
Additions to other property and equipment	(89)	(238)	(1,748)
Additions to restricted investments	(3,976)	(5,361)	(4,599)
Proceeds from the sale of oil and gas properties to third parties		4,525	34,521
Other			29
Net cash provided by (used in) investing activities	$ (1,352,071)	$ (201,413)	$ (357,209)
Net cash provided by (used in) financing activities			
Advances on revolving credit facilities	$ 1,446,000	$ 958,355	$ 391,000
Payments on revolving credit facilities	(1,137,000)	(1,485,537)	(121,819)
Proceeds from the issuances of senior notes	492,425	688,563	
Deferred financing costs	(11,494)	(20,908)	(2,225)
Net proceeds from public equity offering	540,778	490,138	194,304
Repurchases under MEMP unit repurchase program	(11,531)		
Restricted units returned to plan	(1,012)		
Contributions from previous owners		7,233	44,072
Contribution from NGP affiliate		2,013	38,125
Contribution from general partner	570	521	206
Contribution from MRD Segment			1,900
Distributions to partners	(154,852)	(96,643)	(34,436)
Distributions to MRD Segment	(48,880)	(180,260)	(29,280)
Distributions to NGP affiliates		(355,495)	(242,174)
Distributions made by previous owners		(2,552)	(26,455)
Other cash transfers to MRD Segment			(3,751)
Other		(9,013)	(646)
Net cash provided by (used in) financing activities	$ 1,115,004	$ (3,585)	$ 208,821

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Operating Activities. Net income increased by $97.8 million as further discussed above under Results of Operations MEMP Segment, and net cash provided by operating activities increased by $31.2 million. Cash paid for interest during 2014 was $63.7 million compared to $40.4 million during 2013. Net cash provided by operating activities included $12.8 million period-to-period increase in cash flow attributable to the timing of cash receipts and disbursements related to operating activities during 2014 compared to 2013.

Investing Activities. Net cash used in investing activities during 2014 was $1.36 billion, of which $1.08 billion was used to acquire oil and natural gas properties from third parties and $264.2 million was used for additions to oil and gas properties. Cash used in investing activities during 2013 was $201.4 million, of which $38.7 million was used to acquire oil and natural gas properties from a third parties and $161.7 million was used for additions to oil and gas properties. During the year ended December 31, 2013, Tanos had sales proceeds of $4.5 million related to the sale of oil and natural gas properties. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with MEMP s offshore Southern California oil and gas properties. During 2014 and 2013, additions to restricted investments were $4.0 million and $5.4 million, respectively.

Financing Activities. During 2014, MEMP issued a total of 24,840,000 common units generating gross proceeds of approximately $553.3 million offset by approximately $12.5 million of costs incurred in conjunction with the issuance of common units. The net proceeds from these issuances were primarily used to repay borrowings under MEMP s revolving credit facility. In March 2013, MEMP issued 9,775,000 common units generating gross proceeds of approximately $179.4 million offset by approximately $7.6 million of costs incurred in conjunction with the issuance of common units. The net proceeds from this equity offering, including MEMP GP s proportionate capital contribution, partially funded the acquisition of all of the outstanding equity interests in WHT. In October 2013, MEMP issued 16,675,000 common units generating gross proceeds of $331.8 million offset by approximately $13.5 million of costs incurred in conjunction with the issuance of common units. The net proceeds from this equity offering, including MEMP GP s proportionate contribution, were used to repay a portion of outstanding borrowings under MEMP s revolving credit facility.

Distributions to partners during 2014 were $154.9 million compared to $96.6 million during 2013, of which the MRD Segment received $6.1 million during 2014 compared to $26.0 million during 2013. The increase in total distributions is due to both an increase in MEMP s outstanding units between periods and an increase in the declared cash distribution rate per unit. The decrease in distributions to the MRD Segment is due to MRD LLC selling 7,061,294 common units in November 2013 and the distribution of 5,360,912 subordinated units to MRD Holdco in June 2014 in connection with our initial public offering.

MEMP paid $33.9 million to WildHorse Resources in connection with MEMP s April 2014 acquisition of certain oil and natural gas properties in East Texas. MEMP paid $15.0 million to MRD in connection with MEMP s October 2014 acquisition of certain oil and gas properties in the Rockies. MEMP paid $55.4 million to WildHorse Resources in connection with its March 2013 acquisition of all of the outstanding equity interests in WHT and repaid $89.3 million of indebtedness under WHT s credit facility. MEMP paid MRD LLC $96.4 million related to the October 2013 acquisition of certain oil and natural gas properties. Distributions to NGP and affiliates were $355.5 million and Tanos distributed approximately $28.6 million to MRD LLC during 2013.

MEMP s previous owners received contributions of $7.2 million during 2013, of which Tanos received $5.9 million from MRD LLC. Distributions made by MEMP s previous owners totaled $2.6 million in 2013.

MEMP had net payments of $527.2 million under its revolving credit facilities during 2013. Borrowings under revolving credit facilities were used primarily to fund distributions associated with acquisitions of oil and gas properties from affiliates of NGP. MEMP had borrowings of $1.45 billion under its revolving credit facility during 2014 that were used primarily to fund its acquisitions and drilling program. Deferred financing costs of approximately $11.5 million were incurred during 2014 compared to approximately $20.9 million during 2013.

MEMP had unit repurchases of $11.5 million and $1.0 million in units returned to the MEMP GP Long-Term Incentive Plan during 2014.

Net proceeds of $484.0 million from the issuance of the senior notes during 2014 were used to repay borrowings outstanding under MEMP s revolving credit facility. Proceeds of $688.6 million from the issuances of senior notes were generated during 2013 and used to repay borrowings outstanding under MEMP s revolving credit facility.

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

Operating Activities. Net cash flows provided by operating activities increased during 2013 primarily due to an increase in production volumes as a result of acquisitions and increased drilling activities. Cash flows provided by operating activities at the MEMP Segment are used primarily to fund distributions to its partners and additions to oil and gas properties. The previous owners primarily used cash flows provided by operating activities to fund its exploration and development expenditures.

Investing Activities. Cash used in investing activities during 2013 was $201.4 million, of which $38.7 million was used to acquire oil and gas properties located in Wyoming and East Texas and $161.7 million was used for additions to oil and gas properties. Cash used in investing activities during 2012 was $357.2 million, of which $277.6 million was used to acquire oil and gas properties and $107.8 million was used for additions to oil and gas properties. The 2012 acquisitions included $126.9 million of acquisitions in East Texas and $150.7 million of acquisitions in the Permian Basin.

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil properties. During 2013 and 2012, additions to restricted investments were $5.4 million and $4.6 million, respectively.

Proceeds from the sale of oil and gas properties were $4.5 million in 2013 compared to $34.5 million in 2012. The 2013 sales primarily consisted of certain non-operated properties in East Texas while the 2012 sales primarily consisted of certain properties in Garza and Ector counties located in West Texas.

Financing Activities. Cash used in financing activities was $3.6 million in 2013 compared to cash provided by financing activities of $208.8 million in 2012.

MEMP generated total net proceeds of $490.1 million from two separate equity offerings in 2013 as discussed above compared to $194.3 million in December 2012. The net proceeds from the December 2012 offering were used to fund a portion of MEMP s Beta acquisition and to repay indebtedness under MEMP s revolving credit facility.

As discussed above, the net proceeds from the issuance of senior notes during 2013 were used to repay indebtedness under MEMP s revolving credit facility. No senior notes were issued during 2012.

Distributions to partners were $96.6 million during 2013 compared to $34.4 million during 2012 due to increases in both declared distribution rates per unit and increases in the number of outstanding units. Distributions to the MRD Segment totaled $180.3 million in 2013 compared to $29.3 million in 2012. These distributions were primarily associated with the acquisition of assets by MEMP from the MRD Segment. Distributions to NGP affiliates were $355.5 million in 2013 compared to $242.2 million in 2012. The 2013 distribution was associated with the acquisition of assets by MEMP from certain affiliates of NGP in October 2013. The 2012 distribution was associated with the acquisition of assets located offshore Southern California from an affiliate of NGP.

Contributions of $9.8 million were received during 2013 compared to $84.3 million during 2012. Distributions made by the previous owners totaled $2.6 million in 2013 compared to $26.5 million in 2012.

MEMP had net payments of $527.2 million during 2013 related to revolving credit facilities. Borrowings under revolving credit facilities were used primarily to fund distributions associated with acquisitions of oil and gas properties from affiliates of NGP. Net proceeds from the issuance of the senior notes and common unit public equity offerings were used to repay borrowings under MEMP s revolving credit facility. During 2012, MEMP had net borrowings of $269.2 million related to revolving credit facilities. These borrowings were primarily used to fund distributions associated with acquisitions of oil and gas properties from affiliates of NGP. Deferred financing costs of $20.9 million were incurred during 2013 associated with both the senior notes and MEMP s revolving credit facility compared to $2.2 million incurred in 2012 related to revolving credit facilities.

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Debt Agreements MRD Segment

Senior Secured Revolving Credit Facility

In June 2014, we, as borrower, and certain of our subsidiaries, as guarantors, entered into a senior secured revolving credit facility, which is a five-year, $2.0 billion revolving credit facility with a borrowing base of $725 million as of December 31, 2014. The senior secured revolving credit facility is reserve-based, and thus our borrowing base is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. In the future, we may be unable to access sufficient capital under the senior secured revolving credit facility as a result of (i) a decrease in our borrowing base due to a subsequent borrowing base redetermination or (ii) an unwillingness or inability on the part of our lenders to meet their funding obligations.

A further decline in commodity prices could result in a redetermination that lowers our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base, or we could be required to pledge other oil and natural gas properties as additional collateral. If a redetermination of our borrowing base results in our borrowing base being less than our aggregate elected commitments, our aggregate elected commitments will be automatically reduced to the amount of such reduced borrowing base. We do not anticipate having any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the senior secured revolving credit facility.

The revolving credit commitments could be terminated and any outstanding indebtedness together with accrued interest, fees and other obligations under the senior secured revolving credit facility, could be declared immediately due and payable if there is a default under our senior secured revolving credit facility.

We believe we were in compliance with all the financial (interest coverage ratio and current ratio) and other covenants associated with our senior secured revolving credit facility as of December 31, 2014.

See Note 8 to our consolidated and combined financial statements for additional information regarding our senior secured revolving credit facility.

Old Notes

In July 2014, MRD completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes due 2022. The old notes will mature on July 1, 2022 with interest accruing at a rate of 5.875% per annum and payable semi-annually in arrears on January 1 and July 1 of each year. The old notes are governed by an indenture dated as of July 10, 2014. The old notes are fully and unconditionally guaranteed, subject to customary release provisions, on a senior unsecured basis by certain of our existing subsidiaries.

Debt Agreements MEMP Segment

MEMP Revolving Credit Facility

Memorial Production Operating LLC (OLLC), a wholly-owned subsidiary of MEMP, is party to a $2.0 billion revolving credit facility, with a current borrowing base of $1.3 billion that matures in March 2018 and is guaranteed by MEMP and all of its current and future subsidiaries (other than certain immaterial subsidiaries). See Note 8 to our consolidated and combined financial statements included elsewhere in this prospectus for additional information regarding MEMP s revolving credit facility.

Senior Notes

In April 2013, May 2013 and October 2013, MEMP and Memorial Production Finance Corporation (Finance Corp.) (collectively, the MEMP Issuers) issued $300.0 million, $100.0 million and $300.0 million, respectively, of their 7.625% senior unsecured notes due 2021 (the 2021 Senior Notes). The 2021 Senior Notes are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of MEMP s subsidiaries (other than Finance Corp., which is co-issuer of the 2021 Senior Notes, and certain immaterial subsidiaries). The 2021 Senior Notes will mature on May 1, 2021 with interest accruing at a rate of 7.625% per annum and payable semi-annually in arrears on May 1 and November 1 of each year. The 2021 Senior Notes were issued under and are governed by an indenture dated as of April 17, 2013.

In July 2014, the MEMP Issuers completed a private placement of $500.0 million aggregate principal amount of their 6.875% senior unsecured notes due 2022 (the 2022 Senior Notes). The 2022 Senior Notes were issued at 98.485% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of MEMP s subsidiaries (other than Finance Corp., which is co-issuer of the 2022 Senior Notes, and certain immaterial subsidiaries). The 2022 Senior Notes will mature on August 1, 2022 with interest accruing at 6.875% per annum and payable semi-annually in arrears on February 1 and August 1 of each year. The 2022 Senior Notes were issued under and are governed by an indenture dated as of July 17, 2014.

See Note 8 to our consolidated and combined financial statements included elsewhere in this prospectus for additional information regarding the 2021 Senior Notes and 2022 Senior Notes.

Contractual Obligations

In the table below, we set forth our consolidated contractual obligations as of December 31, 2014 disaggregated by business segment. The contractual obligations that will actually be paid in future periods may vary from those reflected in the table because the estimates and assumptions are subjective.

	Payment Due by Period (in thousands)				
Purchase commitment	**Total**	**2015**	**2016-2017**	**2018-2019**	**Thereafter**
Revolving credit facility (1)					
MRD Segment	$ 183,000	$	$	$ 183,000	$
MEMP Segment	412,000			412,000	
Estimated interest payments (2)					
MRD Segment	15,477	3,642	7,283	4,552	
MEMP Segment	47,512	11,179	22,359	13,974	
Senior Notes (3)					
MRD Segment	881,217	37,404	70,500	70,500	702,813
MEMP Segment	1,823,657	89,469	175,500	175,500	1,383,188
Asset retirement obligation (4)					
MRD Segment	12,159		1,684	2,186	8,289
MEMP Segment	110,372		5,189	3,706	101,477
Decommissioning trust agreement (5)					
MEMP Segment	10,350	4,140	6,210		
Operating leases (6)					
MRD Segment	43,625	6,534	13,301	12,219	11,571
MEMP Segment	3,665	788	621	410	1,846
Compression services					
MRD Segment	1,860	1,860			
MEMP Segment	6,526	6,526			
Drilling services					
MRD Segment	48,543	48,543			
Processing Plant Demand Fees (7)					
MRD Segment	375,560	37,941	91,125	57,818	188,676
CO_2 minimum purchase commitment (8)					
MEMP Segment	50,495	9,608	20,330	14,055	6,502

MRD subtotal	1,561,441	135,924	183,893	330,275	911,349
MEMP subtotal	2,464,577	121,710	230,209	619,645	1,493,013
Total	4,026,018	257,634	414,102	949,920	2,404,362

(1) Represents the scheduled future maturities of principal amounts outstanding for the periods indicated. See the notes to the consolidated and combined financial statements included elsewhere in this prospectus for information regarding our revolving credit facilities.

(2) Estimated interest payments are based on the principal amount outstanding under revolving credit facilities at December 31, 2014. In calculating these amounts, we applied the weighted-average interest rate during 2014 associated with such debt. See the notes to the consolidated and combined financial statements included elsewhere in this prospectus for the weighted-average variable interest rate charged during 2014 under these credit facilities. In addition, the estimate of payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2014.

(3) Represents the scheduled future interest payments and principal payments on the Senior Notes. See the notes to the consolidated and combined financial statements included elsewhere in this prospectus for information regarding debt agreements.

(4) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2014 balance sheet. See the notes to the consolidated and combined financial statements included elsewhere in this prospectus for additional information regarding our asset retirement obligations.

(5) Pursuant to a BOEM decommissioning trust agreement, MEMP is required to fund a trust account to comply with supplemental regulatory bonding requirements related to MEMP decommissioning obligations for its offshore Southern California production facilities. See the notes to the consolidated and combined financial statements included elsewhere in this prospectus for additional information.

(6) Primarily represents leases for office space and MEMP s offshore Southern California right-of-way use. See the notes to the consolidated and combined financial statements included elsewhere in this prospectus for additional information regarding operating leases.

(7) Represents minimum commitments to the gatherer. See the notes to the consolidated and combined financial statements included elsewhere in this prospectus for information regarding processing plant demand fees.

(8) Represents a firm agreement, which MEMP assumed in the Wyoming Acquisition, to purchase CO2 volumes.

Critical Accounting Policies and Estimates

Natural Gas and Oil Properties

We use the successful efforts method of accounting to account for our natural gas and oil properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, and seismic costs are expensed as incurred.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved natural gas and oil reserves related to the associated field. Capitalized drilling and development costs of producing natural gas and oil properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and any gain or loss is recognized.

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Proved Natural Gas and Oil Reserves

The estimates of proved natural gas and oil reserves utilized in the preparation of the consolidated and combined financial statements are estimated in accordance with the rules established by the SEC and the FASB. These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements We intend to have our internally prepared reserve report as of December 31 of each year audited for a vast majority of our proved reserves and to prepare internal estimates of our proved reserves as of June 30 of each year.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Oil and gas properties are depleted by field using the units-of-production method. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of natural gas and oil reserves, the remaining estimated lives of natural gas and oil properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

A decline in proved reserves may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of oil and gas producing properties for impairment.

Impairments

Proved natural gas and oil properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

Incentive Units

Prior to our initial public offering, the governing documents of MRD LLC and certain of MRD LLC s subsidiaries, including WildHorse Resources and BlueStone, provided for the issuance of incentive units. Those incentive units were subject to performance conditions that affected their vesting. Compensation cost was recognized only if the performance condition was probable of being satisfied at each reporting date.

WildHorse Resources, BlueStone and MRD LLC each granted incentive units to certain of its members who were key employees at the time of grant. Holders of incentive units were entitled to distributions ranging from 10% to 31.5% when declared, but only after cumulative distribution thresholds (payouts) have been achieved. Payouts would have been generally triggered after the recovery of specified members capital contributions plus a rate of return.

Vesting of incentive units is generally dependent upon an explicit service period, a fundamental change as defined in the respective governing document, and achievement of payout. All incentive units not vested are forfeited if an employee is no longer employed. All incentive units will be forfeited if a holder resigns whether the incentive units are vested or not. If the payouts have not yet occurred, then all incentive units, whether or not vested, will be forfeited automatically (unless extended).

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In connection with the closing of our initial public offering, certain former management members of WildHorse Resources contributed to us their incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources in exchange for approximately 42.3 million shares of our common stock and cash consideration of $30.0 million. See Note 12 to our consolidated and combined financial statements included elsewhere in this prospectus for additional information.

In connection with the restructuring transactions, the MRD LLC incentive units were exchanged for substantially identical units in MRD Holdco, and such incentive units entitle holders thereof to portions of future distributions by MRD Holdco. While any such distributions made by MRD Holdco will not involve any cash payment by us, we will be required to recognize non-cash compensation expense (income), which may be material, in the period in which the performance conditions are probable of being satisfied. The compensation expense (income) recognized by us related to the incentive units will be offset by a deemed capital contribution (distribution) from MRD Holdco. See Note 12 to our consolidated and combined financial statements included elsewhere in this prospectus for additional information.

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, floors, collars, and put options) are used to reduce the impact of natural gas and oil price fluctuations. Interest rate swaps are used to manage exposure to interest rate volatility, primarily as a result of variable rate borrowings under credit facilities. Every derivative instrument is recorded in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative s fair value are recognized currently in earnings as we have not elected hedge accounting for any of our derivative positions.

Income Tax

Prior to our initial public offering, MRD LLC was organized as a pass-through entity for federal income tax purposes and was not subject to federal income taxes; however, certain of its consolidating subsidiaries were taxed as corporations and subject to federal income taxes. We are organized as a taxable C corporation and subject to federal and certain state income taxes. We are also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable margin apportioned to operations in Texas.

Deferred federal and state income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. If it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. In evaluating realizability of deferred tax assets, the Company refers to the reversal periods for available carryforward periods for net operating losses and credit carryforwards, temporary differences, the availability of tax planning strategies, the existence of appreciated assets and estimates of future taxable income and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves and selling prices that are consistent with the Company s internal business forecasts.

A tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority.

In June 2014, we recorded a deferred tax liability in stockholders equity in connection with our initial public offering and the related restructuring transactions. The tax bases of our assets and liabilities changed as a result our initial public offering and the related restructuring transactions, which represented a transaction among stockholders.

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Off Balance Sheet Arrangements

As of December 31, 2014, we had no off balance sheet arrangements.

Recently Issued Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see the notes to the consolidated and combined financial statements included elsewhere in this prospectus. As discussed under Note 2 to our consolidated and combined financial statements included elsewhere in this prospectus, the FASB issued an accounting standards update to improve consolidation guidance for certain types of legal entities in February 2015. The guidance, among other things, modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities and eliminates the presumption that a general partner should consolidate a limited partnership. We will either: (i) continue to consolidate MEMP and become subject to the VIE primary beneficiary disclosure requirements or (ii) no longer consolidate MEMP under the revised VIE consolidation requirements and provide disclosures that apply to variable interest holders that do not consolidate a VIE. The deconsolidation of MEMP would have a material impact on our consolidated financial statements and related disclosures.

Section 107 of the Jumpstart Our Business Startups Act (JOBS Act) provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of natural gas, NGL and oil prices. Natural gas, NGL and oil prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on the prices of natural gas, NGL and oil and our ability to maintain and increase production through acquisitions and exploitation and development projects.

To reduce the impact of fluctuations in natural gas and oil prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into derivative contracts with respect to a portion of our projected natural gas, NGL and oil production through various transactions to provide an economic hedge of the risk related to the future commodity prices received. These transactions may include price swaps, whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, or basis swaps, whereby we will receive a fixed price differential and pay a variable price differential to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pays the excess, if any, of the floating rate over the fixed ceiling price. We also may enter into put options that are designed to provide a fixed price floor with the opportunity for upside. These economic hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to natural gas, NGL and oil price fluctuations. We do not enter derivative contracts for speculative

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trading purposes. Our senior secured revolving credit facility contains various covenants and restrictive provisions which, among other things, limit our ability to enter into commodity price hedges exceeding a certain percentage of production.

At December 31, 2014, the MRD Segment had the following open commodity positions:

	2015	2016	2017	2018
Natural Gas Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (MMBtu)	3,700,000	2,570,000	1,770,000	2,900,000
Weighted-average fixed price	$ 4.15	$ 4.09	$ 4.24	$ 4.27
Collar contracts:				
Average Monthly Volume (MMBtu)	130,000	1,100,000	1,050,000	
Weighted-average floor price	$ 4.00	$ 4.00	$ 4.00	$
Weighted-average ceiling price	$ 4.64	$ 4.71	$ 5.06	$
Natural gas put option contracts:				
Average Monthly Volume (MMBtu)	3,000,000	4,100,000	3,450,000	2,850,000
Weighted-average fixed price	$ 3.75	$ 3.75	$ 3.75	$ 3.75
Weighted-average deferred premium	$ (0.33)	$ (0.36)	$ (0.35)	$ (0.35)
TGT Z1 basis swaps:				
Average Monthly Volume (MMBtu)	1,730,000	220,000	200,000	
Spread Henry Hub	$ (0.09)	$ (0.08)	$ (0.08)	$
Crude Oil Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	46,500	8,500	28,000	31,625
Weighted-average fixed price	$ 91.67	$ 84.80	$ 84.70	$ 84.50
Collar contracts:				
Average Monthly Volume (Bbls)	2,000	27,000		
Weighted-average floor price	$ 85.00	$ 80.00	$	$
Weighted-average ceiling price	$ 101.35	$ 99.70	$	$
Put option contracts:				
Average Monthly Volume (Bbls)	26,000			
Weighted-average fixed price	$ 85.00	$	$	$
Weighted-average deferred premium	$ (3.80)	$	$	$
NGL Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	151,000	185,658		
Weighted-average fixed price	$ 41.61	$ 34.06	$	$

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At December 31, 2014, the MEMP Segment had the following open commodity positions:

	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (MMBtu)	2,605,278	2,692,442	2,450,067	2,160,000	1,914,583
Weighted-average fixed price	$ 4.28	$ 4.40	$ 4.31	$ 4.51	$ 4.75
Collar contracts:					
Average Monthly Volume (MMBtu)	350,000				
Weighted-average floor price	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 5.80	$	$	$	$
Call spreads (1):					
Average Monthly Volume (MMBtu)	80,000				
Weighted-average sold strike price	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.75	$	$	$	$
Basis swaps:					
Average Monthly Volume (MMBtu)	2,940,000	2,508,333	415,000	115,000	
Spread	$ (0.12)	$ (0.04)	$ 0.00	$ 0.15	$
Crude Oil Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	314,281	332,813	326,600	312,000	160,000
Weighted-average fixed price	$ 90.96	$ 85.83	$ 84.38	$ 83.74	$ 85.52
Collar contracts:					
Average Monthly Volume (Bbls)	5,000				
Weighted-average floor price	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 94.00	$	$	$	$
Basis swaps:					
Average Monthly Volume (Bbls)	97,500	95,000			
Spread	$ (7.07)	$ (9.56)	$	$	$
NGL Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	149,200	84,600			
Weighted-average fixed price	$ 43.02	$ 41.49	$	$	$

(1) These transactions were entered into for the purpose of eliminating the ceiling portion of certain collar arrangements, which effectively converted the applicable collars into swaps.

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The MEMP Segment s basis swaps as of December 31, 2014 included in the table above are presented on a disaggregated basis below:

	2015	2016	2017	2018
Natural Gas Derivative Contracts:				
NGPL TexOk basis swaps:				
Average Monthly Volume (MMBtu)	2,280,000	2,103,333	300,000	
Spread Henry Hub	$ (0.11)	$ (0.06)	$ (0.05)	$
HSC basis swaps:				
Average Monthly Volume (MMBtu)	150,000	135,000	115,000	115,000
Spread Henry Hub	$ (0.08)	$ 0.07	$ 0.14	$ 0.15
CIG basis swaps:				
Average Monthly Volume (MMBtu)	210,000			
Spread Henry Hub	$ (0.25)	$	$	$
TETCO STX basis swaps:				
Average Monthly Volume (MMBtu)	300,000	270,000		
Spread Henry Hub	$ (0.09)	$ 0.06	$	$
Crude Oil Derivative Contracts:				
Midway-Sunset basis swaps:				
Average Monthly Volume (Bbls)	57,500	55,000		
Spread Brent	$ (9.73)	$ (13.35)	$	$
Midland basis swaps:				
Average Monthly Volume (Bbls)	40,000	40,000		
Spread WTI	$ (3.25)	$ (4.34)	$	$

Interest Rate Risk

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates such as those in our credit agreement to fixed interest rates. As of December 31, 2014, we did not have open interest rate swap positions.

At December 31, 2014, the MEMP Segment had the following interest rate swap open positions:

Credit Facility	**2015**	**2016**	**2017**
MEMP:			
Average Monthly Notional (in thousands)	$ 314,167	$ 250,000	$ 250,000
Weighted-average fixed rate	1.349%	1.029%	1.620%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives and the sale of our oil and gas production, which we market to energy companies.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates the 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. As of December 31, 2014, our derivative

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contracts are with major financial institutions, certain of which are also lenders under our revolving credit facilities. While collateral is generally not required to be posted by counterparties, credit risk associated with derivative instruments is minimized by limiting exposure to any single counterparty and entering into derivative instruments only with creditworthy counterparties that are generally large financial institutions. Additionally, master netting agreements are used to mitigate risk of loss due to default with counterparties on derivative instruments. We have also entered into the International Swaps and Derivatives Association Master Agreements (ISDA Agreements) with each of our counterparties. The terms of the ISDA Agreements provide us and each of our counterparties with rights of set-off upon the occurrence of defined acts of default by either us or our counterparty to a derivative, whereby the party not in default may set-off all liabilities owed to the defaulting party against all net derivative asset receivables from the defaulting party. At December 31, 2014, MEMP had derivative net assets of $517.1 million. After taking into effect netting arrangements, MEMP had counterparty exposure of $309.8 million related to its derivative instruments. Had certain counterparties failed completely to perform according to the terms of their existing contracts, MEMP would have the right to offset $207.3 million against amounts outstanding under its revolving credit facility at December 31, 2014. At December 31, 2014, we had derivative assets of $255.0 million. After taking into effect netting arrangements, we had counterparty exposure of $155.8 million related to our derivative instruments. Had certain counterparties failed completely to perform according to the terms of their existing contracts, we would have the right to offset $99.2 million against amounts outstanding under our senior secured revolving credit facility at December 31, 2014. See Note 8 to our consolidated and combined financial statements included elsewhere in this prospectus for additional information regarding our revolving credit facilities.

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

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BUSINESS

The Company is a Delaware corporation formed in January 2014. We have two reportable business segments, both of which are engaged in the acquisition, exploration, and development of oil and natural gas properties:

MRD reflects the combined operations of the Company, MRD Operating, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.

MEMP reflects the combined operations of MEMP, its previous owners, and certain historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

Because we control MEMP through our ownership of its general partner, its business and operations are consolidated with ours for financial reporting purposes, even though we do not own any of its common units. As a result, our financial statements and notes thereto included elsewhere in this prospectus consolidate MEMP s business and assets with ours; however, the MEMP Segment s debt is nonrecourse to the Company. Except where expressly noted to the contrary, the following discussion of our business, operations and assets and the use of the terms we , our and us excludes MEMP s business, operations and assets.

Our consolidated and combined financial statements included elsewhere in this prospectus contain information on our segments and geographical areas and are contained herein.

As discussed under Note 2 to the consolidated and combined financial statements included elsewhere in this prospectus, the FASB issued an accounting standards update to improve consolidation guidance for certain types of legal entities in February 2015. The guidance, among other things, modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities and eliminates the presumption that a general partner should consolidate a limited partnership. We will either: (i) continue to consolidate MEMP and become subject to the VIE primary beneficiary disclosure requirements or (ii) no longer consolidate MEMP under the revised VIE consolidation requirements and provide disclosures that apply to variable interest holders that do not consolidate a VIE. The deconsolidation of MEMP would have a material impact on our consolidated financial statements and related disclosures.

MRD

Overview

We are an independent natural gas and oil company focused on the acquisition, exploration and development of natural gas and oil properties with a majority of our activity in the Terryville Complex of North Louisiana, where we are targeting overpressured, liquids-rich natural gas opportunities in multiple zones in the Cotton Valley formation. We are focused on creating shareholder value primarily through the development of our sizeable horizontal inventory.

As of December 31, 2014, our total leasehold position was 335,687 gross (210,854 net) acres. As of December 31, 2014, we had estimated proved reserves of approximately 1,632 Bcfe. As of such date, we operated 99.6% of our proved reserves, 72% of which were natural gas. For the year ended December 31, 2014, 58% of our revenues were attributable to natural gas production, 21% to NGLs and 21% to oil.

Our average net daily production for the year ended December 31, 2014 was approximately 226.9 MMcfe/d (approximately 77% natural gas, 16% NGLs and 7% oil) and our reserve life was approximately 20 years. The Terryville Complex represented 81% of our total net production for the year ended December 31, 2014. As of December 31, 2014, we produced from 129 horizontal wells and 659 vertical wells. During 2014, we completed and brought online 31 horizontal wells in the Terryville Complex, bringing our total number of producing horizontal wells to 52 in our primary formations as of December 31, 2014.

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Recent Developments

Property Swap

In February 2015, we and MEMP completed a transaction (the Property Swap) in which we exchanged certain of our oil and gas properties in East Texas and non-core Louisiana for MEMP s North Louisiana oil and gas properties and approximately $78.0 million in cash, subject to customary adjustments. Terms of the transaction were approved by our board of directors and by its conflicts committee, which is comprised entirely of independent directors. The transaction had an effective date of January 1, 2015.

Amendment to Senior Secured Revolving Credit Facility and Borrowing Base Reaffirmation

On April 13, 2015, we entered into a fourth amendment to our senior secured revolving credit facility to, among other things, add new lenders and permit the repurchase of up to $50.0 million of our common stock. In connection therewith, the lenders under our senior secured revolving credit facility reaffirmed the borrowing base under our facility at $725 million to remain at such level until the next scheduled redetermination, the next interim redetermination or other adjustment to the borrowing base, whichever occurs first.

2014 Developments

MRD Segment

In June 2014, we completed our initial public offering of 49,220,000 shares of common stock at a price to the public of $19.00 per share. Of the 49,220,000 shares offered, 21,500,000 were offered by us and 27,720,000 were offered by the selling stockholder, MRD Holdco. We did not receive any proceeds from the sale of shares by MRD Holdco. We used the net proceeds of approximately $380.2 million from our sale of shares in our initial public offering (i) to redeem the 10.00%/10.75% Senior PIK toggle notes due 2018 (the PIK notes) issued by MRD LLC in their entirety and to pay the applicable premium in connection with such redemption and accrued and unpaid interest to the date of redemption, (ii) together with borrowings of approximately $614.5 million under our $2.0 billion senior secured revolving credit facility entered into in connection with the closing of our initial public offering, to make a cash payment to certain former management members of WildHorse Resources in connection with their contribution to us of their membership interests and incentive units in WildHorse Resources, (iii) to repay borrowings outstanding under WildHorse Resources revolving credit facility and second lien term loan, which we refer to collectively as WildHorse Resources credit agreements, (iv) to reimburse MRD LLC for interest paid on the PIK notes and (v) to pay costs associated with our senior secured revolving credit facility.

In December 2014, our Board of Directors (the Board) authorized the repurchase of up to $50.0 million of the Company s outstanding common stock. Under the share repurchase program, shares may be repurchased from time to time at the Company s discretion on the open market, through block trades or otherwise and are subject to market conditions, as well as corporate, regulatory, and other considerations. Through March 16, 2015, we repurchased $50.0 million shares of common stock, which represents a repurchase of 2,888,684 shares of common stock. MRD has retired all of the shares of common stock repurchased and the shares of common stock are no longer issued or outstanding.

MEMP Segment

Acquisitions of Oil and Gas Properties

In July 2014, MEMP acquired certain oil and natural gas liquids properties in Wyoming from a third party for a purchase price of approximately $906.1 million (the MEMP Wyoming Acquisition).

In March 2014, MEMP acquired certain oil and natural gas producing properties in the Eagle Ford from a third party for a purchase price of approximately $168.1 million (the Eagle Ford Acquisition). In addition, MEMP acquired a 30% interest in the seller s Eagle Ford leasehold.

2022 Senior Notes Offering

In July 2014, MEMP and its wholly-owned subsidiary Memorial Production Finance Corporation (Finance Corp. and, together with MEMP, the MEMP Issuers) completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes due 2022 (the 2022 Senior Notes). The 2022 Senior Notes were issued at 98.485% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by the subsidiary guarantors named in the indenture and by certain future subsidiaries of MEMP s. The 2022 Senior Notes will mature on August 1, 2022 with interest accruing at 6.875% per annum and payable semi-annually in arrears on February 1 and August 1 of each year, commencing on February 1, 2015. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the 2022 Senior Notes receive an investment grade rating from both of two specified ratings agencies. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either of the MEMP Issuers or certain of MEMP s subsidiaries, all outstanding 2022 Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 2022 Senior Notes may declare all the 2022 Senior Notes to be due and payable immediately. The net proceeds from the notes offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility and for general partnership purposes. In January 2015, MEMP repurchased a principal amount of approximately $3.0 million of the 2022 Senior Notes at an average price of 83.000% of the face value of the 2022 Senior Notes. For information regarding the Senior Notes, see Note 8 to the consolidated and combined financial statements included elsewhere in this prospectus.

2014 Equity Offerings

In September 2014, MEMP sold 14,950,000 common units in a public offering (including 1,950,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units). In July 2014, MEMP sold 9,890,000 common units in a public offering (including 1,290,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units). The net proceeds of approximately $541.3 million from these equity offerings were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility.

MEMP Repurchase Program

In December 2014, the board of directors of MEMP GP authorized the repurchase of up to $150.0 million of MEMP s common units. Under the common unit repurchase program, common units may be repurchased from time to time at MEMP s discretion on the open market. The common unit repurchase program does not obligate MEMP to repurchase any dollar amount or specific number of common units and may be discontinued at any time. Through February 1, 2015, MEMP repurchased $41.4 million in common units, which represents a repurchase of 2,809,495 common units. MEMP has retired all common units repurchased and the common units are no longer issued or outstanding.

Our Properties

Cotton Valley Overview

The Cotton Valley formation extends across East Texas, North Louisiana and Southern Arkansas. The formation has been under development since the 1930s and is characterized by thick, multi-zone natural gas and oil reservoirs with well-known geologic characteristics and long-lived, predictable production profiles. Over 21,000 vertical wells have been completed throughout the play. In 2005, operators started redeveloping the Cotton Valley using horizontal drilling and advanced hydraulic fracturing techniques.

Cotton Valley Terryville Complex

We are currently engaged in the horizontal redevelopment of the Terryville Complex in Lincoln Parish, Louisiana utilizing horizontal drilling and completion techniques similar to those employed at the Nan-Su-Gail Field, Carthage Complex in East Texas and other major resource plays across the United States. We have assembled a largely contiguous acreage position in the Terryville Complex of approximately 73,737 gross (61,157 net) acres as of December 31, 2014.

We entered the Terryville Complex via an acquisition from Petrohawk Energy Corporation in April 2010, with the goal of redeveloping the field with horizontal drilling and modern completion techniques. Since that acquisition, we have completed multiple bolt-on acquisitions and in-fill leases to build our current position. We believe the Terryville Complex, which has been producing since 1954, is one of North America s most prolific natural gas fields, characterized by high recoveries relative to drilling and completion costs, high initial production rates with high liquids yields, long reserve life, multiple stacked producing zones, available infrastructure and a large number of service providers.

After initially drilling eight vertical pilot wells in the Terryville Complex, we commenced a horizontal drilling program in 2011 to further delineate and define our position. In 2013, we shifted our operational focus to a full-scale horizontal redevelopment of the Terryville Complex, going from two rigs to four rigs by the end of that year. Additionally, in the fourth quarter of 2013, we moved to drilling on multi-well pads that allow us to more efficiently drill wells and control costs as we develop our stacked pay zones.

Within the Terryville Complex, as of December 31, 2014, we had 1,347 Bcfe of estimated proved reserves and a drilling inventory consisting of 141 gross proved horizontal drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2014. Since initiating our horizontal drilling program in 2011, we have drilled 52 gross horizontal wells in the four primary target zones in the Terryville Complex. Within the Terryville Complex, on a proved reserves basis, we operate approximately 100% of our existing acreage and hold an average working interest of approximately 83% across our acreage.

We expect our redevelopment program to continue to target four of the stacked overpressured pay zones in the Cotton Valley formation zones we term the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink, all of which we are developing with horizontal wells through pad drilling. These four zones have an overall thickness ranging from 525 to 925 feet across our acreage position. Further, we believe there are additional opportunities for redevelopment in the zones above the four main zones.

Based on our reserve report, the Terryville Complex contains more than 15% of our total estimated reserves. The following table summarizes production volumes for the years ended December 31, 2014, 2013 and 2012:

	For the Year Ended December 31,		
	2014	**2013**	**2012**
Production Volumes:			
Oil (MBbls)	716	386	212
NGLs (MBbls)	1,763	1,118	605
Natural gas (MMcfe)	52,512	24,380	11,597
Total (MMcfe)	67,384	33,407	16,502

Average net production (MMcfe/d)	184.6	91.5	45.1

Other North Louisiana

We own and operate approximately 49,198 gross (44,291 net) acres as of December 31, 2014 in our Other North Louisiana region. For the year ended December 31, 2014, our average net daily production from our Other

North Louisiana properties was 11 MMcfe/d, of which 75% was natural gas. See Recent Developments above for further information regarding the February 23, 2015 Property Swap. Following the Property Swap, we own and operate approximately 25,541 gross (16,540 net) acres in our Other North Louisiana region.

East Texas

We owned and operated approximately 54,237 gross (42,844 net) acres as of December 31, 2014 in Texas, where we were producing primarily from the Cotton Valley, Travis Peak and Bossier formations and targeting the Cotton Valley formation for future development. As of December 31, 2014, we had approximately 39 gross proved identified horizontal drilling locations to which we have attributed proved undeveloped reserves. For the year ended December 31, 2014, our average net daily production from our East Texas properties was 26 MMcfe/d, of which 75% was natural gas. Within our East Texas properties, on a proved reserves basis, we operate approximately 98% of our existing properties as of December 31, 2014. See Recent Developments above for further information regarding the February 23, 2015 Property Swap. Following the Property Swap, we no longer own or operate oil and natural gas properties in East Texas.

Rockies

We own approximately 158,515 gross (62,562 net) acres as of December 31, 2014 in our Rockies region. For the year ended December 31, 2014 our average net daily production from this region was 5 MMcfe/d. As of December 31, 2014, we had approximately 1 gross identified vertical drilling location in the Tepee Field in our Rockies properties.

Reserves

Our estimates of proved reserves were prepared by our internal reserve engineers and audited by Netherland, Sewell & Associates, Inc. (NSAI). As of December 31, 2014, we had 1,632 Bcfe of estimated proved reserves. As of this date, our proved reserves were 72% gas and 28% NGLs and oil. The following table provides summary information regarding our estimated proved reserves data and our average net daily production by area based on our reserve report as of December 31, 2014.

Region	Proved Total (Bcfe)	% Gas	% Developed	Average Net Daily Production (MMcfe/d)
Terryville Complex	1,347	72%	35%	185
Other North Louisiana	50	86%	43%	11
East Texas	229	73%	21%	26
Rockies	6	95%	78%	5
Total	1,632	72%	33%	227

Business Strategies

Our primary objective is to build shareholder value through growth in reserves, production and cash flows by developing and expanding our significant portfolio of drilling locations. To achieve our objective, we intend to execute the following business strategies:

Grow production, reserves and cash flow through the development of our extensive drilling inventory. We believe our extensive inventory of low-risk drilling locations, combined with our operating expertise, will enable us to continue to deliver production, reserve and cash flow growth and create shareholder value. We believe that the risk and uncertainty associated with our core acreage positions in the Terryville Complex has been largely reduced through our development activity, and because those positions are in areas with extensive drilling and production history. With 6 rigs running in the Terryville Complex as of December 31, 2014, we are one of the most active drillers in the Cotton Valley formation. We believe multiple vertically stacked producing horizons in the Terryville Complex can be developed using horizontal drilling techniques, thus enhancing the economics of this field.

Enhance returns through prudent capital allocation and continued improvements in operational and capital efficiencies. We continually monitor and adjust our drilling program with the objective of achieving the highest total returns on our portfolio of drilling opportunities. We believe we will achieve this objective by (i) minimizing the capital costs of drilling and completing horizontal wells through knowledge of the target formations, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) targeting specific zones within our leasehold position to maximize our hydrocarbon mix based on the existing commodity price environment and (iv) minimizing operating costs through efficient well management.

Exploit additional development opportunities on current acreage. Our existing asset base provides numerous opportunities for our highly experienced technical team to create shareholder value by increasing our inventory beyond our currently identified drilling locations and ultimately by growing our estimated proved reserves. In the Terryville Complex, we are currently targeting multiple stacked horizons.

Maintain a disciplined, growth oriented financial strategy. We intend to fund our growth primarily with internally generated cash flows from operations and borrowings under our senior secured revolving credit facility while maintaining ample liquidity and access to the capital markets. Furthermore, we plan to hedge a significant portion of our expected production to reduce our exposure to downside commodity price fluctuations and enable us to protect our cash flows and maintain our liquidity to fund our drilling program. Since approximately 60% of our acreage in the Terryville Complex was held by production as of December 31, 2014 and no significant drilling commitments are needed to hold our remaining acreage in the near term, we are able to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program.

Make opportunistic acquisitions that meet our strategic and financial objectives. We will seek to acquire oil and gas properties that we believe complement our existing properties in our core areas of operation. In addition to our focus on the Terryville Complex, we expect to pursue other properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations. We follow a technology driven strategy to establish large, contiguous leasehold positions in the core of prolific basins and opportunistically add to those positions through bolt-on acquisitions over time. We entered into the Terryville Complex through strategic acquisitions and grassroots leasing efforts. We will continue to identify and opportunistically acquire additional acreage and producing assets to complement our multi-year drilling inventory.

Competitive Strengths

We believe that the following strengths will allow us to successfully execute our business strategies.

Large, concentrated position in one of North America s leading plays. As of December 31, 2014, we owned approximately 73,737 gross (61,157 net) acres in the Terryville Complex in Lincoln Parish, which we believe to be one of North America s most prolific liquids-rich natural gas fields, characterized by consistent and predictable geology and multiple stacked pay formations confirmed by extensive vertical well control. During 2014, we have brought 31 wells online within our four primary target zones with average gross 30-day initial production rates of 20.2 MMcfe/d. Approximately 60% of our acreage in the Terryville Complex was held by production at December 31, 2014.

De-risked acreage position with multi-year inventory of liquids-rich drilling opportunities. As of December 31, 2014, we had a drilling inventory consisting of approximately 180 horizontal gross proved undeveloped locations, which includes 141 horizontal gross proved undeveloped locations in the Terryville

Complex. The majority of our drilling activity has been and will continue to be focused in the Terryville Complex, where we produce liquids-rich natural gas from the overpressured Cotton Valley formation. We have used subsurface data from our vertical wells coupled with 3-D seismic data to identify and prioritize our inventory based on returns. This liquids-rich gas formation allows for NGL processing that, when coupled with the condensate produced, results in strong well economics. For the year ended December 31, 2014, 58% of our revenues were attributable to natural gas, 21% to NGLs and 21% to oil.

Significant operational control with low cost operations. On a proved reserves basis, we operate 99.6% of our properties and have operational control of all of our drilling inventory in the Terryville Complex. We believe maintaining operational control will enable us to enhance returns by implementing more efficient and cost effective operating practices, through the selection of economic drilling locations, opportunistic timing of development, continuous improvement of drilling, completion and stimulation techniques and development on multi-well pads. As a result of the contiguous nature of our leasehold in the Terryville Complex, its geologic continuity and cross unit lateral pooling, we are able to drill consistently long laterals, averaging over 5,800 lateral feet in 2014, which helps us to reduce costs on a per-lateral foot basis and increase our returns. Operating in mature basins in North Louisiana allows us to take advantage of the available and extensive midstream infrastructure and accelerate our development plan without encountering significant constraints in either takeaway or processing capacity. Our operational control allows us to focus on operating efficiency, which has resulted in our lease operating costs declining 40% from $0.53 per Mcfe for the year ended December 31, 2013 to $0.32 per Mcfe for the year ended December 31, 2014.

Proven and incentivized executive and technical team. We believe our management and technical teams are one of our principal competitive strengths due to our team s significant industry experience and long history of working together in the identification, execution and integration of acquisitions, cost efficient management of profitable, large scale drilling programs and a focus on rates of return. Additionally, our technical team has substantial expertise in advanced drilling and completion technologies and decades of expertise in operating in the North Louisiana and East Texas regions. The members of our management team collectively have an average of 23 years of experience in the oil and natural gas industry. John A. Weinzierl, our Chief Executive Officer, has 25 years of oil and natural gas industry experience as a petroleum engineer, a strong commercial background and extensive experience acquiring and managing oil and natural gas properties. Our management team has a significant economic interest in us directly and through its equity interests in our controlling stockholder, MRD Holdco. We believe our management team is motivated to deliver high returns, create shareholder value and maintain safe and reliable operations.

Our relationship with MEMP. We own a 0.1% general partner interest in MEMP through our ownership of its general partner, which owns 50% of MEMP s incentive distribution rights. MEMP s objective as a master limited partnership is to generate stable cash flows, allowing it to make quarterly distributions to its limited partners and, over time, to increase those quarterly distributions. As a result of its familiarity with our management team and our asset base and our track record of prior drop-down transactions, we believe that MEMP is a natural purchaser of properties from us that meet its acquisition criteria. We believe this mutually beneficial relationship enhances MEMP s ability to generate consistent returns on its oil and natural gas properties, provides us with a growing source of cash flow from our partnership interests in MEMP and allows us to monetize producing non-core properties. Since MEMP s initial public offering, we have consummated dropdown transactions with MEMP totaling approximately $469 million, including the February 2015 Property Swap. In addition, we may have the opportunity to work jointly with MEMP to pursue certain acquisitions of oil and natural gas properties that may not otherwise be attractive acquisition candidates for either of us individually. While we believe that MEMP would be a preferred acquirer of our mature, non-core assets, we are under no obligation to offer to sell, and it is under no obligation to offer to buy, any of our properties.

Financial strength and flexibility. We intend to continue to fund our organic growth with internally generated cash flows from operations and borrowings under our senior secured revolving credit facility while maintaining ample liquidity for opportunistic acquisitions. We will continue to maintain a disciplined approach

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to spending whereby we allocate capital in order to optimize returns and create shareholder value. We seek to protect these future cash flows and liquidity levels by maintaining a multi-year rolling hedge program. As of December 31, 2014, our total liquidity, consisting of cash on hand and available borrowing capacity under our senior secured revolving credit facility, was approximately $547.0 million.

Our Equity Owners

Our principal stockholder is MRD Holdco, which is controlled by the Funds, which are three of the private equity funds managed by NGP. MRD Holdco owns our common stock directly and, pursuant to a voting agreement, MRD Holdco also has the right to direct the vote of additional shares of our common stock owned by certain former management members of WildHorse Resources. The Funds also collectively indirectly own 50% of MEMP s incentive distribution rights.