Memorial Resource Development Corp.
Form 424B3
May 04, 2015
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Registration No. 333-203496

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 June 2, 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Tenders of old notes may be withdrawn at any time prior to the expiration of the exchange offer.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 May 4, 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, continue 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

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.

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.

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 BlueStone, 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.

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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 June 2, 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

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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;

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- 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.

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

Leases on 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.

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.

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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

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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 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 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 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.

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 June 2, 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.

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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).

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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.

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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.

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 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.

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

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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.

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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.

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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).

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 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.

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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.

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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

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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.

Upon the closing of our initial public offering, we entered into a services agreement with WildHorse Resources and WildHorse Resources Management Company, LLC (WHR Management Company) pursuant to which WHR Management Company agreed to provide operating and administrative services to us relating to the Terryville Complex. In exchange for such services, we paid a monthly management fee to WHR Management Company of approximately $1.0 million excluding third party COPAS income credits. In 2014, we paid approximately $6.2 million in aggregate to WHR Management Company in exchange for its services under the services agreement.

The services agreement was terminated effective March 1, 2015. WHR Management Company is a subsidiary of WildHorse Resources II, LLC, an affiliate of the Company. NGP and certain former management members of WildHorse Resources own WildHorse Resources II, LLC.

Founded in 1988, NGP is a family of private equity investment funds organized to make investments in the energy and natural resources sectors. NGP is part of the investment platform of NGP Energy Capital Management, a premier investment franchise in the natural resources industry with $16.5 billion in cumulative committed capital under management since inception.

Relationship with Memorial Production Partners LP

Through our ownership of its general partner, we control MEMP, a publicly traded limited partnership, and own 50% of MEMP s incentive distribution rights.

MEMP is engaged in the acquisition, exploitation, development and production of oil and natural gas properties in the United States, with assets consisting primarily of producing oil and natural gas properties that are located in Texas, Louisiana, Colorado, Wyoming, New Mexico and offshore Southern California. MEMP 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. Most of MEMP 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. As of December 31, 2014:

MEMP s total estimated proved reserves were approximately 1,454 Bcfe, of which approximately 38% were natural gas and 63% were classified as proved developed reserves; and

MEMP produced from 3,424 gross (1,998 net) producing wells across its properties, with an average working interest of 58%.

In accordance with MEMP s limited partnership agreement, incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of MEMP s available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The minimum quarterly distribution is $0.4750 ($1.90 on an annualized basis) per unit. MEMP GP owns 50% of MEMP s incentive distribution rights, which are freely transferable under the MEMP limited partnership agreement. We own 100% of the voting and economic interests in MEMP GP.

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Following the subordination period under MEMP s limited partnership agreement, which ended on February 13, 2015, MEMP is required to make distributions of available cash from operating surplus for any quarter in the following manner:

first, 99.9% to all unitholders, pro rata, and 0.1% to MEMP GP, until each unitholder receives a total of $0.54625 per unit for that quarter;

second, 85.0% to all unitholders, pro rata, 0.1% to MEMP GP, and 14.9% to the holders of the incentive distribution rights (50% of which are owned by MEMP GP), until each unitholder receives a total of $0.59375 per unit for that quarter; and

thereafter, 75.0% to all unitholders, pro rata, 0.1% to MEMP GP, and 24.9% to the holders of the incentive distribution rights (50% of which are owned by MEMP GP).

Since December 2011, MEMP has increased its quarterly cash distribution from $0.4750 ($1.90 on an annualized basis) per unit to $0.5500 ($2.20 on an annualized basis) per unit, which is its most recently announced distribution rate. We anticipate receiving approximately $0.3 million from our partnership interests in MEMP in 2015 assuming no changes to MEMP s outstanding common units or its last declared cash distribution of $0.55 per unit.

We provide management, administrative, and operations personnel to MEMP under an omnibus agreement. Pursuant to that omnibus agreement, MEMP is required to reimburse us for all expenses incurred by us (or payments made on MEMP s behalf) in conjunction with our provision of general and administrative services to MEMP, including its public company expenses and an allocated portion of the salary and benefits of the executive officers of MEMP s general partner and our other employees who perform services for MEMP or on MEMP s behalf.

We view our relationship with MEMP as a part of our strategic alternatives, and we believe that MEMP will be incentivized to acquire additional suitable assets from us and to pursue acquisitions jointly with us in the future. However, MEMP will regularly evaluate acquisitions and may elect to acquire properties in the future without offering us the opportunity to participate in those transactions. MEMP is free to act in a manner that is beneficial to its interests without regard to ours, which may include electing not to acquire additional assets from us. Although we believe MEMP will desire to acquire properties from us for purchase, MEMP will not have any obligation to acquire properties from us. If MEMP chooses not to acquire properties from us, then our ability to monetize our proved developed properties may be impaired, which could adversely affect our cash flow and net income.

Our Oil and Natural Gas Data

Preparation of Reserve Estimates

Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. For a discussion of risks associated with reserve estimates, please read Risk Factors Risks Related to Our Business 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.

Evaluation and Review of Estimated Reserves. We engaged NSAI to audit our reserves estimates for all of our proved, probable and possible reserves (by volume) at December 31, 2014. MEMP engaged NSAI and Ryder Scott Company, L.P. (Ryder Scott) to audit MEMP s reserves estimates for all of MEMP s proved reserves (by volume) at December 31, 2014. The technical persons responsible for auditing our reserve estimates and

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MEMP s proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our estimated reserves and MEMP s proved reserves. Our technical team meets regularly with NSAI and Ryder Scott reserve engineers to review properties and discuss the assumptions and methods used in the reserve estimation process. We provide historical information to NSAI and Ryder Scott for our properties and MEMP s properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

Internal Engineers. John D. Williams is the technical person at the Company primarily responsible to liaison with and provide oversight of our third-party reserve engineers, NSAI and Ryder Scott, which audited the reserve report for our properties and MEMP s properties. Mr. Williams has been practicing petroleum engineering at the Company since March 2012. Mr. Williams is a Registered Professional Engineer in the State of Texas with over 18 years of experience in the estimation and evaluation of reserves. From April 2005 to March 2012, he held various positions at Southwestern Energy Company, most recently as Reservoir Engineering Manager. From August 1998 to April 2005, he served in various capacities at Ryder Scott, which culminated in his serving as Vice President. Mr. Williams is a graduate of the University of Texas at Austin with a B.S. in petroleum engineering and with a M.S. in petroleum engineering.

Ryder Scott Company, L.P. Ryder Scott is an independent oil and natural gas consulting firm. No director, officer, or key employee of Ryder Scott has any financial ownership in us, the Funds, or any of their respective affiliates. Ryder Scott s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported. Ryder Scott has not performed other work for us, the Funds, or any of their respective affiliates that would affect its objectivity. The audit of estimates of MEMP s proved reserves presented in the Ryder Scott report were overseen by Miles Robert Palke.

Miles Palke has been practicing consulting petroleum engineering at Ryder Scott since 2010. Mr. Palke is a Licensed Professional Engineer in the State of Texas and has over 18 years of practical experience in petroleum engineering, with over 18 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M with a B.S. in petroleum engineering and from Stanford University with a M.S. in petroleum engineering.

Mr. Palke meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Netherland, Sewell & Associates, Inc. NSAI is an independent oil and natural gas consulting firm. No director, officer, or key employee of NSAI has any financial ownership in us, the Funds, or any of their respective affiliates. NSAI s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported. NSAI has not performed other work for us, the Funds, or any of their respective affiliates that would affect its objectivity. The audit of estimates of our reserves and MEMP s proved reserves presented in the NSAI reports were overseen by Mr. Justin S. Hamilton; Mr. David E. Nice; Mr. Richard B. Talley, Jr.; Mr. Philip S. (Scott) Frost; Mr. Eric J. Stevens; Mr. Craig H. Adams; Mr. Nathan C. Shahan; and Mr. William J. Knights.

Justin Hamilton has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Hamilton is a Licensed Professional Engineer in the State of Texas (License No. 104999) and has over 14 years of practical experience in petroleum engineering, with over 14 years of experience in the estimation and evaluation of reserves. He graduated from Brigham Young University in 2000 with a B.S. in mechanical engineering and from the University of Texas in 2007 with an M.B.A.

David Nice has been practicing consulting petroleum geology at NSAI since 1998. Mr. Nice is a Licensed Professional Geoscientist in the State of Texas (License No. 346) and has over 29 years of practical experience in petroleum geosciences, with over 16 years of experience in the estimation and evaluation of reserves. He graduated from University of Wyoming in 1982 with a B.S. in geology and in 1985 with an M.S. in geology.

Richard Talley has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Talley is a Licensed Professional Engineer in the State of Texas (License No. 102425) and in the State of Louisiana (License No. 36998) and has over 16 years of practical experience in petroleum engineering, with over 10 years of experience in the estimation and evaluation of reserves. He graduated from University of Oklahoma in 1998 with a B.S. in mechanical engineering and from Tulane University in 2001 with an M.B.A.

Scott Frost has been practicing consulting petroleum engineering at NSAI since 1984. Mr. Frost is a Licensed Professional Engineer in the State of Texas (License No. 88738) and has over 30 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Vanderbilt University in 1979 with a B.E. in mechanical engineering and from Tulane University in 1984 with an M.B.A.

Eric Stevens has been practicing consulting petroleum engineering at NSAI since 2007. Mr. Stevens is a Licensed Professional Engineer in the State of Texas (License No. 102415) and has over 12 years of practical experience in petroleum engineering, with over 12 years of experience in the estimation and evaluation of reserves. He graduated from Brigham Young University in 2002 with a B.S. in mechanical engineering.

Craig Adams has been practicing consulting petroleum engineering at NSAI since 1997. Mr. Adams is a Licensed Professional Engineer in the State of Texas (License No. 68137) and has over 30 years of practical experience in petroleum engineering, with over 18 years of experience in the estimation and evaluation of reserves. He graduated from Texas Tech University in 1985 with a B.S. in petroleum engineering.

Nathan Shahan has been practicing consulting petroleum engineering at NSAI since 2007. Mr. Shahan is a Licensed Professional Engineer in the State of Texas (License No. 102389) and has over 13 years of practical experience in petroleum engineering, with over 8 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 2002 with a B.S. in petroleum engineering and in 2007 with a M.E. in petroleum engineering.

William Knights has been practicing consulting petroleum geology at NSAI since 1991. Mr. Knights is a Licensed Professional Geoscientist in the State of Texas (License No. 1532) and has over 30 years of practical experience in petroleum geosciences, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Texas Christian University in 1981 with a B.S. in geology and in 1984 with a M.S. in geology.

All eight technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; all eight are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a high degree of confidence that the quantities will be recovered. All of our proved reserves and MEMP s proved reserves as of December 31, 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, management considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

Estimation of Probable and Possible Reserves. Estimates of probable reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Estimates of possible reserves are also inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

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When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserve where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage of recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

Estimated Proved Reserves

The table below identifies our proved reserves as of December 31, 2014 per our reserve report for our three areas:

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MMcfe)
Proved Developed				
Terryville Complex	3,456	332,483	17,919	460,732
Other North Louisiana	223	18,262	273	21,240
East Texas	197	36,850	1,721	48,358
Rockies	28	4,585	11	4,821
Total Proved Developed	3,904	392,180	19,924	535,151
Proved Undeveloped				
Terryville Complex	7,873	632,367	34,453	886,322
Other North Louisiana	327	24,303	377	28,527
East Texas	491	130,739	7,835	180,691
Rockies	8	1,340		1,388
Total Proved Undeveloped	8,699	788,749	42,665	1,096,928
Total Proved				
Terryville Complex	11,329	964,850	52,372	1,347,054
Other North Louisiana	550	42,565	650	49,767
East Texas	688	167,589	9,556	229,049
Rockies	36	5,925	11	6,209
Total Proved Reserves	12,603	1,180,929	62,589	1,632,079

Proved Undeveloped Reserves

As of December 31, 2014, we had 1,097 Bcfe of proved undeveloped reserves, comprised of 9 MMBbls of oil, 789 Bcf of natural gas and 43 MMBbls of NGLs. None of our PUDs as of December 31, 2014 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2014 were due to:

Reclassifications of 72 Bcfe into proved developed reserves for implementation of drilling projects;

Increase of 141 Bcfe of additions from the Terryville Complex due to proving up additional drilling locations; and

Revisions of 270 Bcfe, primarily as a result of performance, in East Texas and the Terryville Complex.

During the year ended December 31, 2014, we spent $92.1 million to convert PUDs to proved developed reserves. As of December 31, 2014 per our reserve report, future development costs relating to the development of PUDs for the years 2015, 2016, 2017, 2018, and 2019 are estimated at approximately $365 million, $464 million, $421 million, $146 million and $2 million, respectively, to capture the balance of drilling the PUD reserves within a five-year timeframe. Approximately $1.2 billion of the future development costs over the next five years are related to development of PUD reserves in the Terryville Complex. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in the upcoming years. All of our PUD locations are scheduled to be drilled prior to the end of December 31, 2019. Based on our current expectations of our cash flows, we believe that we can fund the drilling of our current PUD inventory and our expansions in the next five years from our cash flow from operations and borrowings under our senior secured revolving credit facility.

Reconciliation of PV-10 to Standardized Measure

PV-10 is a non-GAAP financial measure and differs from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies without regard to the specific tax characteristics of such entities. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 of our proved reserves to the Standardized Measure of discounted future net cash flows at December 31, 2014, 2013 and 2012:

	For the Year Ending December 31,		
	2014	**2013**	**2012**
		(In thousands)	
PV-10	$ 3,021,348	$ 1,468,952	$ 1,320,595

Less: present value of future income taxes discounted at 10%	1,058,814		
Standardized measure	$ 1,962,534	$ 1,468,952	$ 1,320,595

Prior to our initial public offering, we were not subject to federal income tax; hence no income taxes were applied to reserve values in previous years.

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Production, Revenue and Price History

The following tables set forth information regarding our production, revenues and realized prices and production costs for the years ended December 31, 2014, 2013, and 2012, respectively:

	For the Year Ended December 31, 2014				
	Terryville Complex	**Other North Louisiana**	**East Texas**	**Rockies**	**Total**
Production Volumes:					
Oil (MBbls)	716	95	43	97	951
NGLs (MBbls)	1,763	72	355	30	2,220
Natural Gas (MMcf)	52,512	2,892	7,227	1,170	63,801
Total (MMcfe)	67,384	3,880	9,616	1,935	82,815
Average net production (MMcfe/d)	184.6	10.7	26.3	5.3	226.9
Average sales price:					
Oil (per Bbl)	$ 89.25	$ 93.48	$ 88.96	$ 88.27	$ 89.54
NGL (per Bbl)	41.52	32.30	26.12	32.81	38.62
Natural Gas (Mcf)	3.61	4.09	3.95	3.49	3.67
Total (Mcfe)	$ 4.85	$ 5.91	$ 4.33	$ 7.06	$ 4.89
Average unit costs per Mcfe:					
Lease operating expense	$ 0.19	$ 1.03	$ 0.95	$ 0.74	$ 0.32

	For the Year Ended December 31, 2013				
	Terryville Complex	**Other North Louisiana**	**East Texas**	**Rockies**	**Total**
Production Volumes:					
Oil (MBbls)	386	89	165	25	665
NGLs (MBbls)	1,118	125	177	37	1,457
Natural Gas (MMcf)	24,380	3,018	6,249	445	34,092
Total (MMcfe)	33,407	4,298	8,297	817	46,819
Average net production (MMcfe/d)	91.5	11.8	22.8	2.2	128.3
Average sales price:					
Oil (per Bbl)	$ 100.18	$ 102.27	$ 102.06	$ 95.78	$ 100.76
NGL (per Bbl)	38.51	30.35	31.33	40.68	36.99
Natural Gas (Mcf)	3.07	3.36	3.79	2.91	3.22
Total (Mcfe)	$ 4.69	$ 5.34	$ 5.54	$ 6.39	$ 4.93
Average unit costs per Mcfe:					
Lease operating expense	$ 0.23	$ 1.16	$ 1.24	$ 1.91	$ 0.53

	For the Year Ended December 31, 2012	
	Rockies	**Total**

	Terryville Complex	Other North Louisiana	East Texas		
Production Volumes:					
Oil (MBbls)	212	61	67	29	369
NGLs (MBbls)	605	97	85	111	898
Natural Gas (MMcf)	11,597	2,431	8,917	1,185	24,130
Total (MMcfe)	16,502	3,372	9,832	2,025	31,731
Average net production (MMcfe/d)	45.1	9.2	26.9	5.5	86.7
Average sales price:					
Oil (per Bbl)	$ 94.98	$ 98.59	$ 97.98	$ 88.05	$ 95.56
NGL (per Bbl)	41.50	34.40	39.08	43.71	40.78
Natural Gas (Mcf)	2.53	2.53	3.13	2.32	2.74
Total (Mcfe)	$ 4.53	$ 4.57	$ 3.84	$ 5.02	$ 4.35
Average unit costs per Mcfe:					
Lease operating expense	$ 0.46	$ 1.34	$ 0.99	$ 1.24	$ 0.77

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Productive Wells

The following table sets forth information regarding productive wells in each of our areas at December 31, 2014.

	Gross	Net	Operated
Terryville Complex	339	271	320
Other North Louisiana	246	138	161
East Texas	144	98	102
Rockies	59	5	4
Total	788	512	587

Acreage

The following table sets forth information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2014.

	Developed Acreage		Undeveloped Acreage		Total Acreage			
	Gross	Net	Gross	Net	Gross	Net	Net HBP	WI
Terryville Complex	47,514	36,604	26,223	24,553	73,737	61,157	60%	83%
Other North Louisiana	47,774	42,867	1,424	1,424	49,198	44,291	97%	90%
East Texas	37,109	30,335	17,128	12,509	54,237	42,844	71%	79%
Rockies	9,466	4,251	149,049	58,311	158,515	62,562	7%	39%
Total	141,863	114,057	193,824	96,797	335,687	210,854	54%	63%

Undeveloped Acreage Expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2014 that will expire over the next three years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates. Of the acreage set to expire in the Terryville Complex for 2015, approximately 90% of the acreage can be retained by either establishing production or through lease extensions. There are no proved reserves attributable to our expiring acreage.

	2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net
Terryville Complex	10,346	9,212	9,113	6,545	3,837	2,156
Other North Louisiana			324	324	1,100	1,100
East Texas	1,917	801	323	116	1,445	1,184
Rockies	15,564	8,878	27,582	17,455	17,787	9,783
Total	27,827	18,891	37,342	24,440	24,169	14,223

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Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2014, 2013, 2012. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. At December 31, 2014, 27 gross (22.9 net) wells were in various stages of drilling or completion.

	For the Year Ending December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	22.0	18.8	22.0	13.3	11.0	10.2
Dry						
Total development wells	22.0	18.8	22.0	13.3	11.0	10.2
Exploratory wells:						
Productive	16.0	14.4	9.0	8.0	7.0	5.6
Dry						
Total exploratory wells	16.0	14.4	9.0	8.0	7.0	5.6
Total wells drilled	38.0	33.2	31.0	21.3	18.0	15.8

Delivery Commitments

The Company has no commitments to deliver a fixed and determinable quantity of our oil or natural gas production to customers in the near future under our existing contracts.

We have entered into gas processing agreements associated with our Terryville Complex production with both related and third party midstream service providers that have volumetric requirements. Information regarding our delivery commitments under these contracts is contained in Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations and Notes 13 and 16 to the consolidated and combined financial statements included elsewhere in this prospectus.

MEMP

The following table summarizes information about MEMP s proved oil and natural gas reserves by geographic region and its average net production as of December 31, 2014.

	Estimated Total Reserves					
	Total (Bcfe)	% Gas	% Oil & NGLs	% Developed	Standardized Measure (in millions)(1)	Average Net Daily Production (MMcfe/d)
East Texas/North Louisiana	545	69%	31%	62%	$ 684	127.0
Rockies	557	9%	91%	61%	1,236	44.4

South Texas	190	68%	32%	79%	321	32.8
Permian Basin	87	4%	96%	51%	175	11.7
California	75	0%	100%	69%	344	11.9
Total	1,454	38%	62%	63%	$ 2,760	227.8

(1) Standardized measure is calculated in accordance with Accounting Standards Codification, or ASC, Topic 932, Extractive Activities Oil and Gas. Because MEMP is a limited partnership, it is generally not subject to federal or state income taxes and thus makes no provision for federal or state income taxes in the calculation of its standardized measure. Standardized measure does not give effect to commodity derivative contracts.

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Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to MEMP s properties as of December 31, 2014, based on MEMP s audited reserve report.

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MMcfe)
Estimated Proved Reserves				
Total Proved Developed	54,526	380,397	35,539	920,783
Total Proved Undeveloped	45,044	179,230	13,939	533,128
Total Proved Reserves	99,570	559,627	49,478	1,453,911

Development of Proved Undeveloped Reserves

As of December 31, 2014, MEMP had 533 Bcfe of proved undeveloped reserves, comprised of 45 MBbls of oil, 179 MMcf of natural gas and 14 MBbls of NGLs. None of MEMP s PUDs as of December 31, 2014 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production. During the fiscal year ended 2014, MEMP s proved undeveloped reserves increased 135 Bcfe, from 398 Bcfe to 533 Bcfe. MEMP made approximately $164.0 million of capital expenditures during the year ended December 31, 2014 to convert approximately 112 Bcfe of proved undeveloped reserves to proved developed reserves. This decrease of 112 Bcfe was offset by a 247 Bcfe increase in proved undeveloped reserves during the year ended December 31, 2014. Based on MEMP s current expectations of its cash flows, MEMP believes that it can fund the drilling of its current PUD inventory and its expansions in the next five years from its cash flow from operations and borrowings under its revolving credit facility.

Production, Revenue and Price History

The following tables summarize MEMP s average net production, average sales prices by product and average production costs and for the years ended December 31, 2014, 2013, and 2012, respectively:

	For the Year Ended December 31, 2014	2013	2012
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	36.78
Natural Gas (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

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Productive Wells

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which MEMP owns an interest, and net wells are the sum of MEMP s fractional working interests owned in gross wells. The following table sets forth information relating to the productive wells in which MEMP owned a working interest as of December 31, 2014.

	Oil		**Natural Gas**	
	Gross	**Net**	**Gross**	**Net**
Operated (1)	766	710	1,444	1,098
Non-operated	263	26	951	164
Total	1,029	736	2,395	1,262

(1) Includes wells operated by the Company on MEMP s behalf.

Developed Acreage

Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2014, substantially all of MEMP s leasehold acreage was held by production. The following table sets forth information as of December 31, 2014 relating to MEMP s leasehold acreage.

	Developed Acreage (1)	
	Gross (2)	**Net (3)**
East Texas/North Louisiana	169,134	85,000
Rockies	137,824	69,691
South Texas	110,038	99,513
Permian Basin	37,766	35,756
Total	454,762	289,960

(1) Developed acres are acres spaced or assigned to productive wells or wells capable of production.
(2) A gross acre is an acre in which MEMP owns a working interest. The number of gross acres is the total number of acres in which MEMP owns a working interest.
(3) A net acre is deemed to exist when the sum of MEMP s fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped Acreage

The following table sets forth information as of December 31, 2014 relating to MEMP s undeveloped leasehold acreage.

	Undeveloped Acreage 1	
	Gross (1)	Net (2)
East Texas/North Louisiana	9,962	3,165
Rockies	88,820	52,072
South Texas	2,717	2,204
Permian Basin	11,867	11,804
Total	113,366	69,245

(1) A gross acre is an acre in which MEMP owns a working interest. The number of gross acres is the total number of acres in which MEMP owns a working interest.

(2) A net acre is deemed to exist when the sum of MEMP s fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

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Drilling Activities

MEMP s drilling activities consist entirely of development wells. The following table sets forth information with respect to wells drilled and completed by MEMP or its previous owners during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value. At December 31, 2014, 12.0 gross (8.0 net) wells were in various stages of completion.

	For the Year Ending December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	102.0	57.3	45.0	32.6	38.0	24.4
Dry	7.0	1.9			1.0	1.0
Exploratory wells:						
Productive						
Dry						
Total wells:						
Productive	102.0	57.3	45.0	32.6	38.0	24.4
Dry	7.0	1.9			1.0	1.0
Total	109.0	59.2	45.0	32.6	39.0	25.4

For purposes of the table above, MEMP s previous owners refers collectively to (a) certain oil and natural gas properties that MEMP acquired from MRD LLC in April and May 2012 for periods after common control commenced through their respective acquisition dates; (b) Rise Energy Operating, LLC and its wholly-owned subsidiaries (except for Rise Energy Operating, Inc.) from February 3, 2009 (inception) through December 11, 2012; (c) certain oil and natural gas properties acquired from WHT Energy Partners (WHT) (the WHT Properties) from February 2, 2011 (inception) through March 2013; and (d) certain oil and natural gas properties acquired through equity and asset transactions on October 1, 2013 from both MRD LLC and certain affiliates of NGP that were a part of the Cinco Group acquisition.

Delivery Commitments

MEMP has no commitments to deliver a fixed and determinable quantity of its oil or natural gas production to customers in the near future under its existing contracts.

Marketing and Major Customers

We market the majority of production from properties we and MEMP operate for both our account and the account of the other working interest owners in our operated properties. We sell substantially all of our production to a variety of purchasers under short-term contracts (less than 12 months). Some production is committed to service and/or sales agreements for longer terms where market access mandates. In all circumstances, the sale of commodities is at prevailing market prices. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. During the year ended December 31, 2014, Energy Transfer Equity, L.P. and subsidiaries accounted for 73% of our revenues, while Phillips 66 and Sinclair Oil & Gas Company accounted for 13% and 12% of MEMP s revenues, respectively. If we were to lose any one of our customers, the loss could temporarily delay production and sale of a portion of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes.

Title to Properties

We believe that we and MEMP have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under natural gas leases, or net profits interests.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties and MEMP s properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 87.5% to 75%.

Seasonality

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

Competition

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

Hydraulic Fracturing

We and MEMP use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete. Hydraulic fracturing is a necessary part of the completion process because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, recompletion, and refracture stimulation projects, or approximately 70% of our total estimated proved reserves as of December 31, 2014 and approximately 36% of MEMP s total estimated proved reserves as of December 31, 2014, require hydraulic fracturing.

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We have and continue to follow applicable industry standard practices and legal requirements for groundwater protection in our and MEMP s operations which are subject to supervision by state and federal regulators (including the Bureau of Land Management on federal acreage). These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by regulatory agencies, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design essentially eliminates a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure.

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements.

Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it in a way that minimizes the impact to nearby surface water by disposing into approved disposal or injection wells. We currently do not discharge water to the surface.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read Business Regulation of Environmental and Occupational Health and Safety Matters Hydraulic Fracturing.

Regulation of the Oil and Natural Gas Industry

Our and MEMP s operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

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

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

Regulation of Production of Oil and Natural Gas

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we and MEMP own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. We own interests in properties located onshore in different U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Some states have the power to prorate production due to the market demand for oil and natural gas. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Environmental and Occupational Health and Safety Matters

Our and MEMP s operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (EPA), issue regulations, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for failure to comply. These laws and regulations may, among other things, require the acquisition of a permit before drilling commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling, completion and production process; restrict the way we handle or dispose of our wastes or of naturally occurring radioactive materials generated by our operations; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require some form of remedial action to prevent or mitigate pollution from current or former operations such as plugging abandoned wells or closing earthen pits; result in the suspension or revocation of necessary permits, licenses and authorizations; require that additional pollution controls be installed; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. 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.

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Changes in environmental laws and regulations occur frequently, and 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 and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous Substance and Waste Handling

Our and MEMP s operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA or the Superfund law, and comparable state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons deemed responsible parties. These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the petroleum exclusion of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. Also, comparable state statutes may not contain a similar exemption for petroleum. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties.

The Oil Pollution Act of 1990 (the OPA) is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on responsible parties for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A responsible party includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities of $350 million per spill. These liability limits may not apply if: a spill is caused by a party s gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a clean-up. We are also subject to analogous state statutes that impose liabilities with respect to oil spills.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act (RCRA), as amended and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA s hazardous waste regulations. It is possible, however, that these wastes, which could include wastes currently generated during our operations, could be designated as hazardous wastes in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as hazardous wastes. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

It is possible that our oil and natural gas operations may require us to manage naturally occurring radioactive materials, or NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams. Some states have enacted regulations governing the handling, treatment, storage and disposal of NORM.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we and MEMP are in substantial compliance with the requirements of CERCLA, RCRA, OPA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water and Other Waste Discharges and Spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act (SDWA), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as SPCC plans, in connection with on-site storage of significant quantities of oil. We and MEMP maintain all required discharge permits necessary to conduct our operations, and we believe we and MEMP are in substantial compliance with their terms.

Hydraulic Fracturing

We and MEMP use hydraulic fracturing extensively in our operations. 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 low permeability 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. 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 SDWA involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. 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. In addition, 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 addition, Congress has from time to time considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process. Also, in the near future we may be subject to regulations that restrict our ability to discharge water produced as part of our production operations, and the ability to use injection wells as a disposal option not only will depend on federal or state regulations but also on whether available injection wells have sufficient storage capacities. 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. The proposed rule is undergoing a public comment period, which ends on June 8, 2015. 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.

Further, in April 2012, the EPA released final rules that subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the new source performance standards (NSPS) and the National Emission Standards for Hazardous Air Pollutants (NESHAPS) 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 clarification 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.

Several states have adopted, or are considering adopting, regulations requiring the disclosure of the chemicals used in hydraulic fracturing and/or otherwise impose additional requirements for hydraulic fracturing activities. 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, Texas requires oil and natural gas operators to disclose to the Texas Railroad Commission and the public the chemicals used in the hydraulic fracturing process, as well as the total volume of water used. On 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 issued a well integrity rule, which updates the requirements for drilling, putting pipe down, and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices, which could lead to increased regulation. For example, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has also commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012, and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review is still pending. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. 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 new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing, and any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

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Air Emissions

The federal Clean Air Act (CAA), as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in April 2012, the EPA released final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and NESHAPS 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 clarification 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.

We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects. We believe that we and MEMP currently are in substantial compliance with all air emissions regulations and that we and MEMP hold all necessary and valid construction and operating permits for our current operations.

Regulation of Greenhouse Gas Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) present an endangerment to public health and the environment, in May 2010, the EPA adopted regulations under existing provisions of the federal CAA that, among other things, established Prevention of Significant Deterioration (PSD) construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. The so-called Tailoring Rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. 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.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In December 2014,

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the EPA published a proposed rule to amend the GHG Reporting Program to add reporting of greenhouse gas emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The rule is undergoing an extended public comment period until February 24, 2015. 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 natural gas facilities.

Restrictions on GHG emissions that may be imposed in various states could adversely affect the oil and natural gas industry. Any GHG regulation could increase our costs of compliance by potentially delaying the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase emission credits; and utilize electric driven compression at facilities to obtain regulatory permits and approvals in a timely manner. While we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Occupational Safety and Health Act

We are also subject to the requirements of the Occupational Safety and Health Act (OSHA) and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our and MEMP s operations are in substantial compliance with the OSHA requirements.

National Environmental Policy Act

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

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Endangered Species Act

The federal Endangered Species Act (ESA) and analogous state statutes 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.

Summary

In summary, we believe we and MEMP are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2014, 2013, and 2012.

Insurance

In accordance with customary industry practice, we and MEMP maintain insurance against many potential operational risks and losses that could be covered by the following policies:

- Commercial General Liability;
- Primary Umbrella / Excess Liability;
- Property;
- Workers Compensation;
- Employer s Liability;
- Maritime Employer s Liability;
- U.S. Longshore and Harbor Workers ;
- Energy Package/Control of Well;
- Oil Pollution Act Liability;
- Pollution Legal Liability;
- Charterer s Legal Liability;
- Non-Owned Aircraft Liability;
- Automobile Liability;
- Directors & Officers Liability;
- Employment Practices Liability;
- Crime; and

Loss of Production (offshore only); Fiduciary

Onshore and Offshore Insurance Program. We and MEMP maintain insurance coverage against potential losses that we believe is customary in the industry. As of December 31, 2014, we maintain commercial general liability insurance, automobile liability insurance and umbrella/excess liability insurance. Our commercial general liability insurance has limits of $1.0 million per occurrence/$2.0 million in the aggregate and a $250,000 self-insured retention. Our general liability insurance covers us for, among other things, legal and contractual liabilities arising out of third party property damage and bodily injury and for sudden and accidental pollution liability. Our automobile liability insurance has limits of $1.0 million per occurrence. Our umbrella/excess liability limits for each occurrence is a minimum of $25.0 million. There is no deductible on our umbrella/excess liability insurance. Our umbrella/excess liability insurance is in addition to our general and automobile liability policy and may be triggered if the general or automobile liability insurance policy limits are exceeded and exhausted. In addition, we maintain an energy package policy that includes control of well coverage (COW) with per occurrence limits for COW ranging from $10.0 million to $100.0 million and retentions ranging from $100,000 to $500,000. Specific to offshore operations, the energy package policy also includes loss of production income coverage insuring us against a loss up to $64.8 million due to a temporary interruption in the oil supply from our offshore facilities as a result of an insured physical loss to our offshore facilities. Our control of well policy insures us for blowout risks associated with drilling, completing and operating our wells. We maintain two separate Pollution Legal Liability (PLL) policies, one for all U.S. onshore operations, excluding California and one for California only. Our PLL non-California insurance policy has limits of $10.0 million per pollution event with a $1.0 million deductible. Our PLL California-only insurance policy has limits of $10.0 million with a $50,000 deductible per event.

As of December 31, 2014, we have insurance policies in effect that are intended to provide coverage for pollution losses including those related to our hydraulic fracturing operations. These policies may not cover fines, penalties or costs and expenses related to government-mandated clean-up of pollution. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We enter into master services agreements, or MSAs, with various service providers. These MSAs allocate potential liabilities and risks between the parties. Under certain MSAs, we indemnify the hydraulic fracturing service providers for pollution and contamination of any kind, damages to or losses from wells or underground formations and damages to property, including pipelines, storage or production facilities. Under certain other MSAs, the service providers indemnify us for pollution or contamination that originates above the surface and is caused by the service provider s equipment or services, unless such pollution or contamination is caused by our gross negligence or willful misconduct, and we indemnify the service providers for all other pollution or contamination that may occur during operations (including that which may result from seepage or any other uncontrolled flow of oil, natural gas or other fluids from the well), unless such pollution or contamination is caused by the service provider s gross negligence or willful misconduct. Generally, we also agree to indemnify the service providers against claims arising from our employees bodily injury or death to the extent that our employees are injured by such hydraulic fracturing operations, unless resulting from the service provider s gross negligence or willful misconduct. Similarly, the service providers generally agree to indemnify us for liabilities arising from bodily injury to or death of any of their employees, unless resulting from our gross negligence or willful misconduct. In addition, the service providers generally agree to indemnify us for loss or destruction of property or equipment that they own, unless resulting from our gross negligence or willful misconduct. In turn, we generally agree to indemnify the service providers for loss or destruction of property or equipment we own, unless resulting from the service provider s gross negligence or willful misconduct.

Despite the general allocation of risk discussed above, we may not succeed in enforcing such contractual allocation of risk, we may be required to enter into a MSA with terms that vary from such allocation of risk and may incur costs or liabilities that fall outside any contractual allocation of risk. As a result, we may incur substantial losses that could materially and adversely affect our financial position, results of operations and cash flows.

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Employees

As of December 31, 2014, we had 505 full-time employees. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Offices

Our executive offices are located at 500 Dallas Street, Suite 1800, Houston, Texas 77002. Our main telephone number is (713) 588-8300.

Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. As of the date hereof, neither we nor MEMP are party to any material legal proceedings.

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MANAGEMENT

Directors and Executive Officers

The following table provides information regarding our current executive officers and directors as of April 3, 2015.

Name	Age	Position
Tony R. Weber	52	Chairman
John A. Weinzierl	46	Chief Executive Officer and Director
William J. Scarff	59	President
Andrew J. Cozby	48	Senior Vice President and Chief Financial Officer
Larry R. Forney	57	Senior Vice President and Chief Operating Officer
Kyle N. Roane	35	Senior Vice President, General Counsel and Corporate Secretary
Gregory M. Robbins	36	Senior Vice President, Corporate Development
Dennis G. Venghaus	33	Vice President and Chief Accounting Officer
Scott A. Gieselman	52	Director
Kenneth A. Hersh	52	Director
Robert A. Innamorati	67	Director
Carol Lee O Neill	51	Director
Pat Wood, III	52	Director

Set forth below is a description of the backgrounds of our executive officers and directors.

Tony R. Weber has served as Chairman of the Board since our formation and as a member of the board of managers of Memorial Resource Development LLC, which has historically owned our predecessor s business (MRD LLC), from September 2011 to June 2014 and a member of the board of directors of Memorial Production Partners GP LLC (MEMP GP), the general partner of Memorial Production Partners LP (the Partnership or MEMP), since September 2011. Mr. Weber currently serves as Managing Partner and Chief Operating Officer for NGP. Prior to joining NGP in December 2003, Mr. Weber was the Chief Financial Officer of Merit Energy Company from April 1998 to December 2003. Prior to that, he was Senior Vice President and Manager of Union Bank of California s Energy Division in Dallas, Texas from 1987 to 1998. In his role at NGP, Mr. Weber serves on numerous private company boards as well as industry groups, IPAA Capital Markets Committee and Dallas Wildcat Committee. He currently serves on the Dean s Council of the Mays Business School at Texas A&M University and was a founding member of the Mays Business Fellows Program.

The Board believes that Mr. Weber s extensive corporate finance, banking and private equity experience bring substantial leadership skill and experience to the Board.

John A. Weinzierl has served as our Chief Executive Officer since our formation, and the Chief Executive Officer of MRD LLC from January 2014 to June 2014 and the Chief Executive Officer and Chairman of MEMP GP since January 2014. Previously, Mr. Weinzierl served as President and Chief Executive Officer of MRD LLC and President, Chief Executive Officer and Chairman of MEMP GP since April 2011. Prior to the completion of the Partnership s initial public offering in December 2011, Mr. Weinzierl was a managing director and operating partner of NGP from December 2010. From July 1999 to December 2010, Mr. Weinzierl worked in various positions at NGP, where he became a managing director in December 2004. Mr. Weinzierl was appointed a

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venture partner of NGP from February 2012 to February 2013. From October 2006 until November 2011, Mr. Weinzierl was a director of Eagle Rock Energy G&P, LLC, the indirect general partner of Eagle Rock Energy Partners, L.P., a (i) natural gas gathering, processing and transportation company and (ii) developer of oil and natural gas properties, where he also served on the compensation committee. Mr. Weinzierl is a registered professional engineer in Texas.

The Board believes Mr. Weinzierl s degree and experience in petroleum engineering and his M.B.A. education, as well as his investment and business expertise honed at NGP, bring valuable strategic, managerial and analytical skills to the board and us.

William J. Scarff has served as our President since our formation, and the President of MRD LLC from January 2014 to June 2014 and MEMP GP since January 2014. From 2000 through January 2014, Mr. Scarff served as President and Chief Executive Officer of several private exploration and production companies sponsored by NGP. Since October 2010, Mr. Scarff served as President and Chief Executive Officer of Propel Energy, LLC. Prior to that, he was President and Chief Executive Officer of Seismic Ventures, Inc. from 2006 to 2009. Since February 2005, Mr. Scarff served as President and Chief Executive Officer of Proton Operating Company, LLC and from 1999 to 2005, he was President and Chief Executive Officer of Proton Energy, LLC and its affiliates. From 1978 to 1999, Mr. Scarff held a variety of positions of increasing responsibility in Marathon Oil Company, Anadarko Production Company, Burlington Resources, Texas Meridian Resource Corporation and Hilcorp Energy Company.

Andrew J. Cozby has served as our Senior Vice President and Chief Financial Officer since November 2014, our Vice President and Chief Financial Officer from April 2014 to November 2014, the Vice President and Chief Financial Officer of MEMP GP since February 2012 and the Vice President, Finance of MRD LLC from April 2011 to June 2014. From February 2011 to April 2011, Mr. Cozby served as Senior Vice President and Chief Financial Officer of Energy Maintenance Services (EMS Global). Prior to that, he was Chief Financial Officer of Greystone Oil & Gas LLP and Greystone Drilling LP from May 2006 to December 2010. From 2000 to May 2006, Mr. Cozby was Director of Finance for Enterprise Products Partners LP and held various corporate finance positions with its affiliates GulfTerra Energy Partners, LP and El Paso Energy Partners, LP. Prior to that, Mr. Cozby held positions with J.P. Morgan from 1998 to 2000.

Larry R. Forney has served as our Senior Vice President and Chief Operating Officer since November 2014, our Vice President and Chief Operating Officer from June 2014 to November 2014, our Vice President, Operations from April 2014 to June 2014, the Vice President and Chief Operating Officer of MEMP GP since January 2013 and the Vice President, Operations and Asset Management of MRD LLC from December 2011 to June 2014. He also served as Vice President, Operations and Asset Management of MEMP GP from December 2011 to December 2012. From August 2008 to December 2011, Mr. Forney served as President of Mossback Management LLC, a private entity providing contract operating and engineering consulting services, including managing all operations and related business functions for Hungarian Horizon Energy, Ltd and Central European Drilling, Ltd in Budapest, Hungary from July 2010 to August 2011. From July 2004 to July 2008, Mr. Forney served as Vice President of Operations for Greystone Oil & Gas LLP and Managing Director of Greystone Drilling LP. Mr. Forney served as Vice President of Operations for Greystone Petroleum LLC from 2002 until 2004. Mr. Forney was Vice President and Treasurer of Goldrus Producing Company from 1997 to 2002. From 1990 to 1997, Mr. Forney held various positions for the Kelley Oil companies, which culminated in his serving concurrently as Vice President of Operations for Kelley Oil Corporation and Vice President of Concorde Gas Marketing. Prior to 1990, Mr. Forney held various drilling, production and facility construction positions with Pacific Enterprises Oil Corporation and Kerr-McGee Corporation. Mr. Forney is a registered professional engineer in Texas.

Kyle N. Roane has served as our Senior Vice President, General Counsel and Corporate Secretary since November 2014, our Vice President, General Counsel and Corporate Secretary from our formation to November 2014, and the Vice President, General Counsel and Corporate Secretary of MRD LLC from January 2014 to

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June 2014 and MEMP GP since January 2014. Previously, Mr. Roane served as the General Counsel and Corporate Secretary of MRD LLC and MEMP GP since February 2012. From 2005 to February 2012, Mr. Roane practiced corporate and securities law at Akin Gump Strauss Hauer & Feld L.L.P.

Gregory M. Robbins has served as our Senior Vice President, Corporate Development since November 2014, our Vice President, Corporate Development from April 2014 to November 2014 and the Vice President of Corporate Development of MRD LLC from January 2013 to June 2014 and MEMP GP since January 2013. Previously, he served as Treasurer of MRD LLC and MEMP GP from June 2011 to April 2012 and Director of Corporate Development from April 2012 to January 2013. From October 2010 to April 2011, Mr. Robbins served as Vice President and Controller of Quality Electric Steel Castings, LP. Prior to that, he was a Vice President with Guggenheim Partners, LLC from May 2006 to October 2010. Mr. Robbins worked for Wells Fargo Energy Capital, LLC from 2004 to March 2006 and Comerica Bank, Inc. from 2002 to 2004.

Dennis G. Venghaus has served as our Vice President and Chief Accounting Officer since January 2015 and our Chief Accounting Officer since our formation, and the Controller of MRD LLC from January 2012 to June 2014 and MEMP GP since January 2012. Prior to joining MRD LLC and MEMP GP, Mr. Venghaus was with Opportune LLP from June 2010 to January 2012 as a Manager in the Complex Financial Reporting group. From September 2004 through June 2010, he held various positions in the audit practice at PricewaterhouseCoopers LLP in Houston, Texas, primarily serving energy clients. Mr. Venghaus is a Certified Public Accountant.

Scott A. Gieselman has served as a member of the Board since our formation and as a member of MRD LLC s board of managers from September 2011 to June 2014 and MEMP GP s board of directors since September 2011. Mr. Gieselman has been a managing director of NGP since April 2007. Mr. Gieselman has served as a member of the board of directors of Rice Energy, Inc. since January 2014. From 1988 to April 2007, Mr. Gieselman worked in various positions in the investment banking energy group of Goldman, Sachs & Co., where he became a partner in 2002.

The Board believes that Mr. Gieselman s considerable financial and energy investment banking experience, as well as his experience on the boards of numerous private energy companies bring important and valuable skills to the Board.

Kenneth A. Hersh has served as a member of the Board since our formation and as a member of MRD LLC s board of managers from April 2011 to June 2014 and MEMP GP s board of directors since April 2011. Mr. Hersh is the Chief Executive Officer of NGP Energy Capital Management and a managing partner of NGP and has served in those or similar capacities since 1989. Mr. Hersh served as a director of NGP Capital Resources Company from November 2004 until September 2014. Mr. Hersh served as a director of Resolute Energy Corporation from September 2009 to March 2012, as a director of Eagle Rock Energy G&P, LLC, the indirect general partner of Eagle Rock Energy Partners, L.P., from March 2006 until June 2011 and Energy Transfer Partners, L.L.C., the indirect general partner of Energy Transfer Partners, L.P., a natural gas gathering and processing and transportation and storage and retail propane company, from February 2004 through December 2009, and served as a director of LE GP, LLC, the general partner of Energy Transfer Equity, L.P., from October 2002 through December 2009. Mr. Hersh currently serves on the Dean s Council of the Harvard Kennedy School and on the Advisory Councils of the Graduate School of Business at Stanford University and The Bendheim Center for Finance at Princeton University. He is also a member of the World Economic Forum where he has been a featured speaker at its annual meeting held in Davos, Switzerland.

The Board believes that Mr. Hersh brings extensive knowledge to the board and us through his experiences in the energy industry as an investor, involvement in complex energy-related transactions and his position as Chief Executive Officer of NGP Energy Capital Management and co-manager of NGP s investment portfolio. Mr. Hersh also brings a wealth of industry-specific transactional skills, entrepreneurial ideas and a personal network of public and private capital sources that the Board believes will bring us opportunities that we may not otherwise have.

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Robert A. Innamorati has served as a member of the Board since June 2014 and as chairman of the Board s audit committee since June 2014. Mr. Innamorati has served as President of Robert A. Innamorati & Co. Inc., a private investment and advisory firm, since 1995. He previously served as President of a privately-owned diversified investment company with assets in excess of $1.5 billion from 2007 until 2012. Mr. Innamorati also held positions with Banc One Capital Corporation, Drexel Burnham Lambert & Co. Inc., PaineWebber, Inc. and Blyth Eastman Dillon & Co., Inc. He previously served for six years as a special agent with the United States Secret Service in Washington, D.C. and two years in the United States Marine Corps Reserves. Mr. Innamorati served as a member of the board of directors of MEMP GP from August 2012 until December 2014. Mr. Innamorati served as a board member of The Texas Rangers Baseball Club until February 2013, where he served as chairman of the compensation committee and as a member of the finance committee. Mr. Innamorati has also served as a board member for several private companies.

The board believes that Mr. Innamorati s extensive corporate finance, banking and private equity experience and audit committee experience brings substantial leadership skill and experience to the Board.

Carol Lee O Neill has served as a member of the Board since June 2014. Ms. O Neill has been Vice President of Strategy and Key Initiatives at Barry-Wehmiller Group, a private company engaged in the global equipment business based primarily in the US and Europe since October 2013. From April 2010 to September 2013, Ms. O Neill was Senior Vice President of Packaging at Spartech Corporation. Prior to that, Ms. O Neill served as President of Flying Food Group from August 2007 to April 2010. From 1996 to 2007, Ms. O Neill held various senior management positions at Sealed Air Corporation.

The Board believes that Ms. O Neill s considerable financial and leadership experience brings important and valuable skills to the Board.

Pat Wood, III has served as a member of the Board since June 2014. Mr. Wood has served as a principal of Wood3 Resources, an energy infrastructure developer, since July 2005. From 2001 until July 2005, Mr. Wood served as chairman of the Federal Energy Regulatory Commission. From 1995 until 2001, he chaired the Public Utility Commission of Texas. Prior to 1995, Mr. Wood was an attorney with Baker & Botts, a global law firm, and an associate project engineer with Arco Indonesia, an oil and gas company, in Jakarta. Mr. Wood currently serves on the board of directors of Dynegy Inc., Quanta Services Inc. and SunPower Corp.

The Board believes that Mr. Wood s prior experience in corporate leadership, government and regulatory oversight, in addition to experience in public company board leadership will provide significant contributions to the Board.

Board Composition

We have seven directors. Assuming that the group consisting of MRD Holdco and certain former management members of WildHorse Resources management continue to control more than 50% of our common stock, we intend to continue to avail ourselves of the controlled company exception under NASDAQ rules, which eliminates the requirements that we (i) have a majority of independent directors, (ii) maintain a compensation committee or (iii) maintain an independent nominating function. We are required, however, to have an audit committee comprised entirely of independent directors within the permitted phase-in period under NASDAQ rules. We are in compliance with this requirement and have an audit committee composed entirely of independent directors.

As a result of the size of that group s ownership of our common stock, that group is able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions.

If at any time we cease to be a controlled company under NASDAQ rules, the Board will take all action necessary to comply with the NASDAQ rules, including appointing a majority of independent directors to the

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Board and ensuring we have a compensation committee and a nominating and corporate governance committee, each composed entirely of independent directors, subject to a permitted phase-in period. We will cease to qualify as a controlled company once that group ceases to control a majority of our voting stock.

The Board currently consists of a single class of directors each serving one year terms. After we cease to be a controlled company, the Board will be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, and such directors being removable only for cause.

In evaluating director candidates, the Board will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the ability of the Board to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the Board to fulfill their duties. We have no minimum qualifications for director candidates. In general, however, the Board will review and evaluate both incumbent and potential new directors in an effort to achieve diversity of skills and experience among our directors and in light of the following criteria:

- experience in business, government, education, technology or public interests;
- high-level managerial experience in large organizations;
- breadth of knowledge regarding our business or industry;
- specific skills, experience or expertise related to an area of importance to us, such as energy production, consumption, distribution or transportation, government, policy, finance or law;
- moral character and integrity;
- commitment to our stockholders interests;
- ability to provide insights and practical wisdom based on experience and expertise;
- ability to read and understand financial statements; and
- ability to devote the time necessary to carry out the duties of a director, including attendance at meetings and consultation on company matters.

Although we do not have a policy in regard to the consideration of diversity in identifying director nominees, qualified candidates for nomination to the Board are considered without regard to race, color, religion, gender, ancestry or national origin.

Director Independence

The Board has determined that, under NASDAQ listing standards, Messrs. Innamorati and Wood and Ms. O Neill are independent directors. In addition, the Board has determined that, under NASDAQ listing standards and taking into account any applicable committee standards and rules under the Exchange Act, Messrs. Innamorati and Wood and Ms. O Neill are independent directors under the heightened independence requirements for service on an audit committee.

Audit Committee

Messrs. Innamorati and Wood and Ms. O Neill serve as the members of the Audit Committee. The Board has determined that Mr. Innamorati is an audit committee financial expert as defined by the SEC. Each member of the Audit Committee meets the criteria for independence of Audit Committee members set forth in Rule 10A-3(b)(1) under the Exchange Act.

The principal duties of the Audit Committee are to assist the Board in fulfilling its responsibility to oversee management regarding:

- systems of internal control over financial reporting and disclosure controls and procedures;

- the integrity of the financial statements;
- the qualifications, engagement, compensation, independence and performance of the independent auditors and our internal audit function;
- compliance with legal and regulatory requirements;
- review of material related party transactions; and
- compliance with and adequacy of the code of business conduct and ethics and review and, if appropriate, approve any requests for written waivers sought with respect to any executive officer or director under, the code of business conduct and ethics.

Code of Conduct

The Board has adopted a code of business conduct and ethics (the Code of Conduct) that applies to all directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. The Code of Conduct is available in the Corporate Governance section of our website at www.memorialrd.com. The purpose of the Code of Conduct is to promote honest and ethical conduct, including the ethical handling of actual or apparent conflicts of interest between personal and professional relationships; to promote full, fair, accurate, timely and understandable disclosure in periodic reports required to be filed by us; and to promote compliance with all applicable rules and regulations that apply to us and our officers.

Executive Compensation

As an emerging growth company, we are not required to include a Compensation Discussion and Analysis section and have elected to comply with the scaled disclosure requirements applicable to emerging growth companies.

This executive compensation disclosure provides an overview of the 2014 executive compensation program for our named executive officers (NEOs) identified below. For 2014, our NEOs were:

Name	Principal Position
John A. Weinzierl	Chief Executive Officer
William J. Scarff	President
Andrew J. Cozby	Senior Vice President and Chief Financial Officer

Many of our NEOs also serve as executive officers of MEMP GP. MEMP reimburses us for costs and expenses incurred for its or MEMP GP s benefit pursuant to the terms of the omnibus agreement, including an allocated portion of each such executive s compensation. See Certain Relationships and Related Party Transactions Omnibus Agreement for more information about the omnibus agreement. We have sole responsibility and authority for compensation-related decisions for our executive officers and other personnel.

We employ a compensation philosophy that emphasizes pay-for-performance, based on a combination of our performance and the individual s impact on our performance and places the majority of each officer s compensation at risk. The compensation of our executive and non-executive officers includes a significant component of incentive compensation based on our performance. The performance metrics governing incentive compensation are not tied in any way to the performance of entities other than us. We believe this pay-for-performance approach generally aligns the interests of our executive officers with that of our stockholders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance fails to meet expectations.

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Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our stockholders, and to reward success in reaching such goals. We use three primary elements of compensation to fulfill that design salary, cash bonus and long-term equity incentive awards. Cash bonuses and equity incentives (as opposed to salary) represent the performance driven elements. They are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals cash bonuses reflects their relative contribution to achieving or exceeding annual goals, and the determination of specific individuals long-term incentive awards is based on their expected contribution in respect of longer term performance objectives.

We do not have a defined benefit or pension plan for our executive officers because we believe such plans primarily reward longevity rather than performance. We provide a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance.

Summary Compensation Table

Although we were formed in January 2014 and did not incur any cost or liability with respect to compensation, management incentive or retirement benefits for our executive officers for the fiscal year ended December 31, 2013 or for any prior periods, the following table presents the historical executive compensation awarded to, earned by or paid to our predecessor s named executive officers, John A. Weinzierl, Andrew J. Cozby and Larry R. Forney, for the fiscal year ended December 31, 2013, as well as the compensation awarded to, earned by or paid to our NEOs for the fiscal year ended December 31, 2014. Amounts in the table below are inclusive of amounts allocated to MEMP under the omnibus agreement.

Name and Position(1)	Year	Salary	Bonuses	Restricted Stock Awards (2)	Restricted Unit Awards (3)	All Other Compensation (4)	Total (5)
John A. Weinzierl	2014	$ 300,000	$	$ 3,500,009	$ 2,800,008	$ 1,178,246	$ 7,778,263
(Chief Executive Officer) (6)	2013	187,500	518,750		2,249,996	2,618,171	5,574,417
William J. Scarff (President)	2014	$ 279,167	$ 320,833	$ 2,500,001	$ 1,999,990	$ 623,354	$ 5,723,345
Andrew J. Cozby	2014	$ 300,000	$ 280,000	$ 1,849,992	$ 1,300,010	$ 586,100	$ 4,316,102
(Senior Vice President and Chief Financial Officer)	2013	250,000	259,375		1,207,885	1,293,509	3,010,769
Larry R. Forney (Senior Vice President and Chief Operating Officer)	2013	$ 250,000	$ 259,375	$	$ 1,231,255	$ 1,281,549	$ 3,022,179

(1) Positions reflect current positions with the Company. In 2013, Mr. Weinzierl was President and Chief Executive Officer of our predecessor, Mr. Cozby was Vice President, Finance of our predecessor, and Mr. Forney was Vice President, Operations and Asset Management of our predecessor. Mr. Scarff joined the Company and our predecessor on January 31, 2014.

(2) Reflects the aggregate grant date fair value of restricted stock awards in accordance with FASB ASC Topic 718 granted under the Memorial Resource Development Corp. 2014 Long Term Incentive Plan (the MRD Plan) calculated by multiplying the number of restricted shares granted to each executive by the closing price of our common stock on the date of grant. For information about assumptions made in the valuation of these awards, see Note 11 to our consolidated and combined financial statements included elsewhere in this prospectus.

(3) Reflects the aggregate grant date fair value of restricted unit awards in accordance with FASB ASC Topic 718 granted under the Memorial Production Partners GP LLC Long-Term Incentive Plan (the MEMP Plan) calculated by multiplying the number of restricted units granted to each executive by the closing price of MEMP common units on the date of grant. For information about assumptions made in the valuation of these awards, see Note 11 to our consolidated and combined financial statements included elsewhere in this prospectus.

(4) Amounts include (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) one-time performance bonus in both 2013 and 2014, (iii) the dollar value of life insurance premiums paid on behalf of such officer, (iv) the dollar value of short and long term disability insurance premiums paid on behalf of such officer and (v) quarterly distributions on MEMP unit awards.

(5) Includes, in addition to the grant date fair value of MEMP unit awards described in footnote 2, amounts reimbursed by MEMP for portions of compensation allocated to MEMP.

(6) Mr. Weinzierl was awarded a grant of 9,695 restricted shares under the MRD Plan and 11,327 MEMP restricted units under the MEMP Plan on January 9, 2015 in lieu of his cash bonus for 2014. The grant date fair value of such awards was determined by multiplying the number of restricted shares and units granted by the closing price of our common stock and MEMP s common units on the date of grant of $18.05 per share and $15.45 per unit, respectively. The value of these awards has been excluded from the table above as the awards were granted subsequent to fiscal year 2014.

Narrative Disclosure to Summary Compensation Table

The following supplemental table presents the components of All Other Compensation for each of our NEOs and our predecessor s named executive officers for the years ended December 31, 2014 and 2013, respectively:

Name	Year	One-Time Performance Bonus (1)	Distributions Paid On Unit Awards	Matching Contributions 401(k)	Other	Total
John A. Weinzierl	2014	$ 702,000	$ 458,156	$ 15,600	$ 2,490	$ 1,178,246
	2013	2,293,200	316,564	5,917	2,490	2,618,171
William J. Scarff	2014	$ 507,000	$ 98,346	$ 15,600	$ 2,408	$ 623,354
Andrew J. Cozby	2014	$ 351,000	$ 217,010	$ 15,600	$ 2,490	$ 586,100
	2013	1,146,600	129,419	15,000	2,490	1,293,509
Larry R. Forney	2013	$ 1,146,600	$ 117,459	$ 15,000	$ 2,490	$ 1,281,549

(1) Each of these one-time performance bonuses were granted by our predecessor on dates prior to our initial public offering.

The primary elements of compensation for our NEOs are base salary, cash bonuses and long-term equity-based compensation awards. Our NEOs also receive certain retirement, health, welfare and additional benefits as described below.

Compensation Elements	**Characteristics**	**Primary Objective**
Base salary	Fixed annual cash compensation. Salaries may be increased from time to time based on our NEOs responsibilities and performance.	Recognize performance of job responsibilities and attract and retain talented employees.
Cash bonuses	Performance-based annual cash incentive.	Encourage focus on near-term performance goals and reward achievement of those goals.
Long-term equity incentives	Equity-based compensation awards subject to time and performance based vesting provisions.	Emphasize our long-term growth, encourage maximizing equity value and retain talented employees.
Severance provisions	Salary continuation and COBRA reimbursement upon certain qualifying terminations.	Encourage continued attention and dedication of key individuals and focus their attention when considering strategic alternatives.
Retirement savings 401(k) plan	Qualified 401(k) retirement plan benefits are available for our NEOs and all other full-time employees.	Provide an opportunity for tax-efficient savings.
Health and welfare benefits	Health and welfare benefits are available to our NEOs and other full-time employees.	Provide benefits to meet the health and welfare needs of our employees and their families.

Grants of Plan-Based Awards

The following table sets forth certain information with respect to grants of plan-based awards to our NEOs in 2014.

	Restricted Common Stock Awards			**Restricted MEMP Common Unit Awards**		
Name	**Grant Date**	**All Other Equity Awards: Number of Restricted Shares (#) (1)**	**Grant Date Fair Value (2)**	**Grant Date**	**All Other Equity Awards: Number of Restricted Units (#) (1)**	**Grant Date Fair Value (3)**
John A. Weinzierl	06/18/14	184,211	$ 3,500,009	05/30/14	125,168	$ 2,800,008
William J. Scarff	06/18/14	131,579	$ 2,500,001	05/30/14	89,405	$ 1,999,990
Andrew J. Cozby	06/18/14	97,368	$ 1,849,992	05/30/14	58,114	$ 1,300,010

(1) Represents the amount of restricted common stock and units awarded to our NEOs under the MRD Plan and MEMP Plan, none of which are tied to performance based criteria.
(2) Reflects the aggregate grant date fair value of restricted stock awards in accordance with FASB ASC Topic 718 granted under the MRD Plan calculated by multiplying the number of restricted shares granted to each executive by the closing price of our common stock on the date of grant.
(3) Reflects the aggregate grant date fair value of restricted unit awards in accordance with FASB ASC Topic 718 granted under the MEMP Plan calculated by multiplying the number of restricted units granted to each executive by the closing price of MEMP common units on the date of grant.

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Outstanding Equity Awards at December 31, 2014

The following table provides information concerning equity awards outstanding for our NEOs at December 31, 2014.

	Restricted Common Stock Awards			Restricted MEMP Common Unit Awards		
Name	**Vesting Date (1)**	**Number of Shares That Have Not Vested (#)**	**Market Value of Shares That Have Not Vested (2)**	**Vesting Date (3)**	**Number of Units That Have Not Vested (#)**	**Market Value of Units That Have Not Vested (4)**
John A. Weinzierl	Various	184,211	$ 3,321,324	Various	249,928	$ 3,646,450
William J. Scarff	Various	131,579	$ 2,372,369	Various	89,405	$ 1,304,419
Andrew J. Cozby	Various	97,368	$ 1,755,545	Various	114,027	$ 1,663,654

(1) One-fourth of each restricted stock award vests on the first, second, third and fourth anniversaries of the date of grant. Of the 413,158 non-vested restricted stock awards presented in the table, approximately 103,329 vests in each of 2015, 2016, 2017 and 2018.

(2) Amounts derived by multiplying the total number of restricted common stock awards outstanding for each NEO by the closing price of our common stock at December 31, 2014 of $18.03 per share.

(3) One-third vests on the first, second, and third anniversaries of each date of grant. Of the 453,360 non-vested restricted MEMP common unit awards presented in the table, approximately 210,286 vests in 2015, 152,179 vests in 2016 and 90,895 vests in 2017. There were 50,088 restricted MEMP common units that vested on January 9, 2015.

(4) Amounts derived by multiplying the total number of restricted MEMP common unit awards outstanding for each NEO by the closing price of the MEMP common units at December 31, 2014 of $14.59 per unit.

Narrative Disclosure to Outstanding Equity Awards at December 31, 2014 Table

In connection with the successful completion of our initial public offering, we granted certain employees, including our NEOs, bonuses. The bonuses were granted in the form of restricted stock awards that are governed by the MRD Plan described below. The restricted stock awards were granted following the closing of our initial public offering and will vest ratably on a four-year annual vesting schedule.

Option Exercises and Stock Vested

The following table sets forth certain information with respect to equity-based awards held by our NEOs, which vested in 2014.

	Restricted MEMP Common Unit Awards			
Name (1)	**Vesting Date (2)**	**Number of Units That Have Vested (#) (3)**	**Unit Price On Vesting Date**	**Market Value of Units That Have Vested (4)**

John A. Weinzierl	01/09/14	43,070	$ 21.99	$ 947,109
	05/31/14	41,817	22.37	935,446
Andrew J. Cozby	01/09/14	7,161	$ 21.99	$ 157,470
	05/31/14	27,342	22.37	611,641

(1) William J. Scarff joined the Company, our predecessor and MEMP GP as President on January 31, 2014, and did not hold any position with the Company, our predecessor or MEMP GP prior to that time.

(2) One-third of each restricted unit award vests on the first, second, and third anniversaries of each date of grant.

(3) Represents gross vesting amounts prior to any units withheld for taxes.

(4) Amounts derived by multiplying the total number of restricted common unit awards outstanding for each NEO by the closing price of MEMP s common units on the respective vesting date.

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Change in Control Agreements

We have entered into change in control agreements with our executive officers. The change in control agreements continue in effect until the earlier of (i) a separation from service other than on account of a qualifying termination (as defined below), (ii) the Company s satisfaction of all of our obligations under the change in control agreement, or (iii) the execution of a written agreement between the Company and the executive officer terminating the change in control agreement.

Under the terms of each change in control agreement, if an executive s employment is terminated on account of a qualifying termination, then subject to such executive s signing and not revoking a separation agreement and release of claims, then such executive will be entitled to:

- receive a lump sum payment of equal to a specified percentage of such executive s (a) annual base salary and (b) target bonus, in each case, at the highest rate in effect during the twelve month period prior to the date in which the qualifying termination occurs, which percentage is 250/200/150%;

- the vesting of all outstanding unvested awards previously granted to such executive under the MRD Plan;

- reimbursement for the amount of COBRA continuation premiums (less required co-pay) until the earlier of (a) twelve months following the qualifying termination and (b) such time as such executive is no longer eligible for COBRA continuation coverage;

- financial counseling services for twelve months following the qualifying termination, subject to a maximum benefit of $30,000; and

- outplacement counseling services for twelve months following the qualifying termination, subject to a maximum value of $30,000.

For purposes of the above, qualifying termination means, as to any executive, the separation of service on account of (i) an involuntary termination by the Company without cause or (ii) such executive s voluntary resignation for good reason, in each case, within six months prior to, or twenty-four months following, a change in control. The term cause means (a) such executive s commission of, conviction for, plea of guilty or nolo contendere to a felony or a crime involving moral turpitude; (b) engaging in conduct that constitutes fraud, gross negligence or willful misconduct that results or would reasonably be expected to result in material harm to the Company or our business or reputation; (c) breach of any material terms of such executive s employment, including any of our policies or code of conduct; or (d) failure to perform such executive s duties for the Company. The term good reason means the occurrence of one of the following without an executive s express written consent (i) a material reduction of such executive s duties, position or responsibilities, or such executive s removal from such position and responsibilities, unless such executive is offered a comparable position (i.e., a position of equal or greater organizational level, duties, authority, compensation, title and status); (ii) a material reduction by the Company of such executive s base compensation (base salary and target bonus) as in effect immediately prior to such reduction; or (iii) such executive is requested to relocate (except for office relocations that would not increase such executive s one way commute by more than 50 miles). The term change in control has the meaning ascribed to such term in the MRD Plan and is described in the discussion below under

MRD 2014 Long Term Incentive Plan Merger, recapitalization or change in control.

In the event that the Board determines that payments to be made to an executive under the change in control agreement would constitute excess parachute payments subject to excise tax under Section 4999 of the Internal Revenue Code (the Code), then the amount of such payments shall either (i) be reduced so that such payments will not be subject to such excise tax or (ii) paid in full, whichever results in the better net after tax position for the executive.

Indemnification Agreements

We have entered into indemnification agreements with each of our directors and executive officers. These agreements require us to indemnify these individuals to the fullest extent permitted under Delaware law against liability that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We believe that the limitation of liability provision in our amended and restated certificate of incorporation and the indemnification agreements facilitates our ability to continue to attract and retain qualified individuals to serve as directors and executive officers.

Executive Compensation Plans

The following summarizes the material terms of the long-term incentive compensation plan in which our NEOs are eligible to participate.

MRD 2014 Long Term Incentive Plan

We adopted the MRD Plan for the employees of the Company and our directors. The description of the MRD Plan set forth below is a summary of the material features of the MRD Plan. This summary is qualified in its entirety by reference to the MRD Plan, a copy of which has been filed as Exhibit 10.1 to our current report on Form 8-K filed on June 16, 2014. The purpose of the MRD Plan is to provide a means to attract and retain individuals to serve as our directors and employees by affording such individuals a means to acquire and maintain ownership of awards, the value of which is tied to the performance of our common stock. The restricted stock awards granted in connection with the closing of our initial public offering should be not be interpreted as representative of the MRD Plan awards that may be granted in the future.

The MRD Plan provides for potential grants of: (i) incentive stock options qualified as such under U.S. federal income tax laws (incentive options); (ii) stock options that do not qualify as incentive stock options (nonstatutory options, and together with incentive options, options); (iii) stock appreciation rights; (iv) restricted stock awards; (v) restricted stock units (RSUs); (vi) bonus stock; (vii) dividend equivalents, (viii) performance awards; (ix) annual incentive awards; and (x) other stock-based awards (collectively referred to as awards).

Administration

The Board administers the MRD Plan pursuant to its terms and all applicable state, federal or other rules or laws, and may delegate its duties and responsibilities as MRD Plan administrator to a committee composed of two or more directors, subject to certain limitations. The MRD Plan administrator has the power to determine to whom and when awards will be granted, determine the amount of awards (measured in cash or in shares of our common stock), proscribe and interpret the terms and provisions of each award agreement (the terms of which may vary), make determinations of fair market value, accelerate the exercise terms of an option, delegate duties under the MRD Plan, terminate, modify or amend the MRD Plan in certain cases and execute all other responsibilities permitted or required under the MRD Plan. The MRD Plan administrator is limited in its administration of the MRD Plan only in the event that a performance award or annual incentive award intended to comply with section 162(m) of the Code requires the Board to be composed solely of outside directors at a time when not all directors are considered outside directors for purposes of section 162(m) of the Code; at such time any director that is not qualified to grant or administer such an award will recuse himself from the Board s actions with regard to that award.

Securities Offered

The maximum aggregate number of shares of common stock that may be issued pursuant to any and all awards under the MRD Plan shall not exceed 19,250,000 shares, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or the expiration of awards, as provided under the MRD Plan.

If common stock subject to any award is not issued or transferred, or ceases to be issuable or transferable for any reason, including (but not exclusively) because shares are withheld or surrendered in payment of taxes or any exercise or purchase price relating to an award or because an award is forfeited, terminated, expires unexercised, is settled in cash in lieu of common stock or is otherwise terminated without a delivery of shares, those shares of common stock will again be available for issue, transfer or exercise pursuant to awards under the MRD Plan to the extent allowable by law.

Options. We may grant options to eligible persons including: (i) incentive options (only to our employees or those of our subsidiaries) which comply with section 422 of the Code; and (ii) nonstatutory options. The exercise price of each option granted under the MRD Plan will be stated in the option agreement and may vary; however, the exercise price for an option must not be less than the fair market value per share of common stock as of the date of grant (or 110% of the fair market value for certain incentive options), nor may the option be re-priced without the prior approval of our stockholders. Options may be exercised as the Board determines, but not later than ten years from the date of grant. The Board will determine the methods and form of payment for the exercise price of an option (including, in the discretion of the Board, payment in common stock, other awards or other property) and the methods and forms in which common stock will be delivered to a participant.

Stock appreciation rights (SARs) may be awarded in connection with an option (or as SARs that stand alone, as discussed below). SARs awarded in connection with an option will entitle the holder, upon exercise, to surrender the related option or portion thereof relating to the number of shares for which the SAR is exercised. The surrendered option or portion thereof will then cease to be exercisable. Such SAR is exercisable or transferable only to the extent that the related option is exercisable or transferable.

SARs. A SAR is the right to receive a share of common stock, or an amount equal to the excess of the fair market value of one share of the common stock on the date of exercise over the grant price of the SAR, as determined by the Board. The exercise price of a share of common stock subject to the SAR shall be determined by the Board, but in no event shall that exercise price be less than the fair market value of the common stock on the date of grant. The Board will have the discretion to determine other terms and conditions of a SAR award.

Restricted stock awards. A restricted stock award is a grant of shares of common stock subject to a risk of forfeiture, performance conditions, restrictions on transferability and any other restrictions imposed by the Board in its discretion. Restrictions may lapse at such times and under such circumstances as determined by the Board. Except as otherwise provided under the terms of the MRD Plan or an award agreement, the holder of a restricted stock award will have rights as a stockholder, including the right to vote the common stock subject to the restricted stock award or to receive dividends on the common stock subject to the restricted stock award during the restriction period. The Board shall provide, in the restricted stock award agreement, whether the restricted stock will be forfeited and reacquired by us upon certain terminations of employment. Unless otherwise determined by the Board, common stock distributed in connection with a stock split or stock dividend, and other property distributed as a dividend, will be subject to restrictions and a risk of forfeiture to the same extent as the restricted stock award with respect to which such common stock or other property has been distributed.

Restricted stock units. RSUs are rights to receive common stock, cash, or a combination of both at the end of a specified period. The Board may subject RSUs to restrictions (which may include a risk of forfeiture) to be specified in the RSU award agreement, and those restrictions may lapse at such times determined by the Board. Restricted stock units may be settled by delivery of common stock, cash equal to the fair market value of the specified number of shares of common stock covered by the RSUs, or any combination thereof determined by the Board at the date of grant or thereafter. Dividend equivalents on the specified number of shares of common stock covered by RSUs may be paid on a current or deferred basis, as determined by the Board on or following the date of grant.

Bonus stock awards. The Board will be authorized to grant common stock as a bonus stock award. The Board will determine any terms and conditions applicable to grants of common stock, including performance criteria, if any, associated with a bonus stock award.

Dividend equivalents. Dividend equivalents are rights to receive cash, stock, other awards, or other property equal in value to dividends paid with respect to a specified number of shares of common stock. Dividend equivalents may be awarded on a free-standing basis or in connection with another award. The Board may provide that dividend equivalents shall be paid or distributed when accrued or shall be deemed to have been reinvested in additional common stock, awards, or other investment vehicles, and be subject to such restrictions on transferability and risks of forfeiture, as determined by the Board.

Performance awards and annual incentive awards. The Board may designate that certain awards granted under the MRD Plan constitute performance awards. A performance award is any award the grant, exercise or settlement of which is subject to one or more performance standards. An annual incentive award is an award based on a performance period of the fiscal year, and is also conditioned on one or more performance standards. One or more of the following business criteria for the company, on a consolidated basis, and/or for specified subsidiaries, may be used by the Board in establishing performance goals for such performance awards or annual incentive awards that are intended to meet the performance-based compensation criteria of section 162(m) of the Code: (i) earnings per share; (ii) increase in revenues; (iii) increase in cash flow; (iv) increase in cash flow from operations; (v) increase in cash flow return; (vi) return on net assets; (vii) return on assets; (viii) return on investment; (ix) return on capital; (x) return on equity; (xi) economic value added; (xii) operating margin; (xiii) contribution margin; (xiv) net income; (xv) net income per share; (xvi) pretax earnings; (xvii) pretax operating earnings after interest expense and before incentives, service fees and extraordinary or special items; (xviii) pretax earnings before interest, depreciation and amortization; (xix) total stockholder return; (xx) debt reduction; (xxi) market share; (xxii) change in the fair market value of the common stock; (xxiii) operating income; or (xxiv) lease operating expenses. The Board may exclude the impact of any of the following events or occurrences which the Board determines should appropriately be excluded: (i) asset write-downs; (ii) litigation, claims, judgments or settlements; (iii) the effect of changes in tax law or other such laws or regulations affecting reported results; (iv) accruals for reorganization and restructuring programs; (v) any extraordinary, unusual or nonrecurring items as described in the Accounting Standards Codification Topic 225, as the same may be amended or superseded from time to time; (vi) any change in accounting principles as defined in the Accounting Standards Codification Topic 250, as the same may be amended or superseded from time to time; (vii) any loss from a discontinued operation as described in the Accounting Standards Codification Topic 360, as the same may be amended or superseded from time to time; (viii) goodwill impairment charges; (ix) operating results for any business acquired during the calendar year; (x) third party expenses associated with any acquisition by us or any subsidiary; and (xi) to the extent set forth with reasonable particularity in connection with the establishment of performance goals, any other extraordinary events or occurrences identified by the Board. The Board may also use any of the above goals determined on an absolute or relative basis or as compared to the performance of a published or special index deemed applicable by the Board including, but not limited to, the Standard & Poor s 500 stock index or a group of comparable companies.

Other stock-based awards. The Board is authorized, subject to limitations under applicable law, to grant such other awards that may be denominated or payable in, valued in whole or in part by reference to, or otherwise based on, or related to, our common stock, as deemed by the Board to be consistent with the purposes of the MRD Plan. These other awards could include convertible or exchangeable debt securities, other rights convertible or exchangeable into common stock, purchase rights for common stock, awards with value and payment contingent upon performance of the Company or any other factors designated by the Board, and awards valued by reference to the book value of our common stock or the value of securities of or the performance of specified subsidiaries of the Company. The Board shall determine the terms and conditions of these awards.

Performance awards or annual incentive awards granted to eligible persons who are deemed by the Board to be covered employees pursuant to section 162(m) of the Code shall be administered in accordance with the rules and regulations issued under section 162(m) of the Code. The Board may also impose individual performance criteria on the awards, which, if required for compliance with section 162(m) of the Code, will be approved by our stockholders. In any calendar year, a covered employee may not be granted an award of more than 2.5 million of our shares of stock, or cash-based award having a value of more than $50 million.

Tax withholding. At our discretion, subject to conditions that the Board may impose, a participant s minimum statutory tax withholding with respect to an award may be satisfied by withholding from any payment related to an award or by the withholding of shares of common stock issuable pursuant to the award based on the fair market value of the shares.

Merger, recapitalization or change in control. If any change is made to our capitalization, such as a stock split, stock combination, stock dividend, exchange of shares or other recapitalization, merger or otherwise, which results in an increase or decrease in the number of outstanding shares of common stock, appropriate adjustments will be made by the Board in the shares subject to an award under the MRD Plan. We will also have the discretion to make certain adjustments to awards in the event of a change in control, such as accelerating the exercisability of options or SARs, requiring the surrender of an award, with or without consideration, or making any other adjustment or modification to the award we feel is appropriate in light of the specific transaction.

A change in control is defined in the MRD Plan to mean (i) subject to certain exceptions, the acquisition by a person or group of more than 50% of shares of our outstanding common stock or the total combined voting power of our outstanding securities, (ii) individuals who constitute our incumbent board cease for any reason to constitute at least a majority of the Board, (iii) a merger, consolidation, reorganization or business combination or the sale or other disposition of all or substantially all of our assets or an acquisition of assets of another entity unless following such transaction, (a) our stockholders continue to own more than 50% of the voting power of the resulting entity, (b) no person (excluding any entity controlled by or under common control with NGP Energy Capital Management, L.L.C.) beneficially owns, directly or indirectly, 20% or more of the then outstanding shares of common stock or common equity interests of the resulting entity or the combined voting power of the then outstanding voting securities to the extent that such ownership results solely from ownership of the Company prior to the transaction or event and (c) a majority of the members of the board of directors of the resulting entity were members of our incumbent board at the time of the action of the Board providing for such transaction or event or (iv) approval by our stockholders of the Company s complete liquidation or dissolution.

MEMP GP Long Term Incentive Plan

In December 2011, the MEMP Plan was adopted for employees, officers, consultants and directors of MEMP GP and any of its affiliates, including the Company and its predecessor, who perform services for MEMP. The MEMP Plan consists of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The MEMP Plan initially limits the number of common units that may be delivered pursuant to awards under the plan to 2,142,221 common units. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The MEMP Plan is administered by a plan administrator, which is currently the board of directors of MEMP GP.

If an award recipient s service with MEMP GP or its affiliates is terminated prior to full vesting of the restricted units for any reason, then the award recipient will forfeit all unvested restricted units, except that, if an award recipient s service is terminated either by MEMP GP (or an affiliate) without cause or by the award recipient for good reason (as such terms are defined in the restricted unit agreement) within one year following the occurrence of a change of control, all unvested restricted units will become immediately vested in full. If an award recipient s service with MEMP GP or its affiliates is terminated by (i) MEMP GP with cause or (ii) by the award recipient s resignation and engagement in Competition (as such term is defined in the restricted unit agreement) prior to full vesting of the restricted units, then MEMP GP has the right, but not the obligation, to repurchase the restricted units at a price per restricted unit equal to the lesser of (x) the fair market value of such restricted unit as of the date of the repurchase and (y) the price paid by the award recipient for such restricted unit.

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Director Compensation

Our officers or employees who also serve as our directors do not receive additional compensation for their service as a director. Our directors who are not our officers or employees do receive compensation as non-employee directors. The following table presents information regarding compensation paid to the non-employee directors during the year ended December 31, 2014.

Name	Fees Earned or Paid in Cash	Restricted Stock Awards (2)	All Other Compensation	Total
Robert A. Innamorati (1)	$ 61,610	$ 99,997	$	$ 161,607
Carol Lee O Neill	54,110	99,997		154,107
Pat Wood, III	54,110	99,997		154,107

(1) Mr. Innamorati serves as chairman of the Audit Committee. Mr. Innamorati also served as a member of the board of directors of MEMP GP from August 2012 until December 2014. During the year ended December 31, 2014, Mr. Innamorati earned fees of $91,667, was awarded $100,011 of MEMP restricted common units under the MEMP Plan, and received quarterly distributions of $17,602 from MEMP restricted common units.

(2) In connection with the closing of our initial public offering in June 2014, each non-employee director was granted 5,263 shares of MRD common stock under the MRD Plan. The aggregate grant date fair value of the restricted common stock awards granted under the MRD Plan was calculated by multiplying the number of restricted common shares granted to each director by the closing price of our common stock on the date of grant (i.e., $19.00). For information about assumptions made in the valuation of these awards, see Note 11 to our consolidated and combined financial statements included elsewhere in this prospectus. At December 31, 2014, Messrs. Innamorati and Wood and Ms. O Neill each had 5,263 shares of restricted common stock outstanding.

For 2015, the following compensation has been approved for the non-employee directors:

- an annual retainer of $125,000 for each director payable quarterly in arrears;
- an annual equity grant under the MRD Plan of $125,000 of restricted common stock, which was granted in January 2015, was based on the price per share on the date of grant, and will vest one year from the date of grant; and
- an additional retainer of $7,500 for service as the chair of the audit committee.

In addition, non-employee directors are reimbursed for all out-of-pocket expenses incurred in connection with attending Board or committee meetings. Each director is indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Corporate Restructuring

In connection with our initial public offering, we engaged in restructuring events and transactions with certain affiliates and our existing equity holders. Pursuant to a contribution agreement, MRD LLC contributed to us substantially all of its assets, comprised of: (i) 100% of the ownership interests in Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C., Black Diamond Minerals, LLC, Beta Operating Company, LLC, Memorial Resource Finance Corp. and MRD Operating LLC; (ii) 99.9% of the membership interests in WildHorse Resources, the owner of our properties in the Terryville Complex; and (iii) MEMP GP (including MEMP GP s ownership of 50% of MEMP s incentive distribution rights). In exchange, we issued 128,665,677 shares of our common stock to MRD LLC, which MRD LLC then immediately distributed to MRD Holdco. We assumed the obligations of MRD LLC under its $350 million 10.00%/10.75% Senior PIK toggle notes due 2018 (PIK notes), including the obligation to reimburse MRD LLC for the June 15, 2014 interest payment made on the PIK notes.

Pursuant to another contribution agreement, certain former management members of WildHorse Resources contributed to us their outstanding incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources, and we issued 42,334,323 shares of our common stock and paid cash consideration of approximately $30.0 million to such former management members of WildHorse Resources.

Voting Agreement

On June 18, 2014, we entered into a voting agreement with MRD Holdco, WHR Incentive LLC (WHR Incentive), a limited liability company beneficially owned by Anthony Bahr (Bahr) and Jay Graham (Graham), and certain former management members of WildHorse Resources that contributed their ownership of WildHorse Resources to us in connection with the closing of our initial public offering. Among other things, the voting agreement provides that those former management members of WildHorse Resources will vote all of their shares of our common stock as directed by MRD Holdco.

The voting agreement also provides MRD Holdco with the right to designate up to three nominees to the Board, provided that such number of nominees shall be reduced to two, one and zero if the Funds and their affiliates collectively own less than 35%, 15% and 5%, respectively, of the outstanding shares of our common stock. The voting agreement also requires us and the stockholders party thereto to take all necessary actions, to the fullest extent permitted by applicable law (including with respect to any fiduciary duties under Delaware law), including voting their shares of our common stock, to cause the election of the nominees designated by MRD Holdco. In addition, the voting agreement provides that for so long as MRD Holdco has the right to designate two directors to the Board, we will cause any committee of the Board to include in its membership at least one director designated by MRD Holdco, except to the extent that such membership would violate applicable securities laws or stock exchange rules.

The voting agreement shall terminate (a) as to the former management members of WildHorse Resources as a group, on the first date on which MRD Holdco, the Funds and their respective affiliates and the former management members of WildHorse Resources collectively beneficially own less than 50% of our outstanding shares of common stock and (b) as to any individual former management member of WildHorse Resources, at such time as such former management member no longer beneficially owns any shares of our common stock. The voting agreement shall remain in force and effect with respect to MRD Holdco and the Company until such time as MRD Holdco, the Funds and their respective affiliates collectively beneficially own less than 5% of the outstanding shares of our common stock.

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Registration Rights Agreement

In connection with the closing of our initial public offering, we entered into a registration rights agreement with MRD Holdco and former management members of WildHorse Resources, Graham and Bahr. Pursuant to the registration rights agreement, we have agreed to register the sale of shares of our common stock under certain circumstances.

Demand Rights

Subject to the limitations set forth below, each of MRD Holdco, Graham and Bahr (or their permitted transferees) has the right to require us, by written notice, to prepare and file a registration statement registering the offer and sale of a certain number of their shares of common stock. Generally, we are required to provide notice of the request within five business days following the receipt of such demand request to all other holders of registrable securities, who may, in certain circumstances, participate in the registration. Subject to certain exceptions, we will not be obligated to effect a demand registration within 90 days after the closing of any underwritten offering of shares of our common stock. Further, we are not obligated to effect, (i) at the request of MRD Holdco, more than a total of three demand registrations through December 31, 2016 (one of which was effected in November 2014) or, after January 1, 2017, more than one demand registration per calendar year; and (ii) more than two demand registrations at the request of each of Graham or Bahr.

We are also not obligated to effect any demand registration in which the anticipated aggregate offering price included in such offering is less than $50 million. Once we are eligible to effect a registration on Form S-3, any such demand registration may be for a shelf registration statement. We will be required to use all commercially reasonable efforts to maintain the effectiveness of any registration statement until all shares covered by such registration statement have been sold.

In addition, each of MRD Holdco, Graham and Bahr (or their permitted transferees) has the right to require us, subject to certain limitations, to effect a distribution of any or all of their shares of common stock by means of an underwritten offering. In general, any demand for an underwritten offering (other than the first requested underwritten offering made in respect of a prior demand registration and other than a requested underwritten offering made concurrently with a demand registration) shall constitute a demand request subject to the limitations set forth above.

Piggyback Rights

Subject to certain exceptions, if at any time we propose to register an offering of common stock or conduct an underwritten offering, whether or not for our own account, then we must notify MRD Holdco, Graham and Bahr (or their permitted transferees) of such proposal at least five business days before the anticipated filing date or commencement of the underwritten offering, as applicable, to allow them to include a specified number of their shares in that registration statement or underwritten offering, as applicable.

Conditions and Limitations; Expenses

These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with our obligations under the registration rights agreement, regardless of whether a registration statement is filed or becomes effective.

Omnibus Agreement

On December 14, 2011, in connection with the closing of MEMP s initial public offering, MRD LLC entered into an omnibus agreement with MEMP and its general partner. In connection with the restructuring transactions, we succeeded to all of MRD LLC s duties and obligations under the omnibus agreement.

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Pursuant to the omnibus agreement, MEMP is required to reimburse us for all expenses incurred by us (or payments made on MEMP s behalf) in conjunction with our provision of general and administrative services to MEMP, including, but not limited to, public company expenses and an allocated portion of the salary and benefits of the executive officers of MEMP s general partner and our other employees who perform services for MEMP or on MEMP s behalf. MEMP is also obligated to reimburse us for insurance coverage expenses we incur with respect to MEMP s business and operations and with respect to director and officer liability coverage for the officers and directors of MEMP s general partner.

Pursuant to the omnibus agreement, we will indemnify MEMP s general partner and MEMP against (i) title defects and (ii) income taxes attributable to pre-closing ownership or operation of the assets we contributed to MEMP in connection with MEMP s initial public offering, including any income tax liabilities related to such contribution occurring on or prior to the closing of MEMP s initial public offering.

Our indemnification obligation survived until December 2014 with respect to title defects and will survive for sixty days after the expiration of the applicable statute of limitations with respect to income taxes. All title claims are subject to a $25,000 per claim de minimus exception and an aggregate $2,000,000 deductible.

Pursuant to the omnibus agreement, MEMP must indemnify us for any liabilities incurred by us attributable to the operating and administrative services provided to MEMP under the omnibus agreement, other than liabilities resulting from our bad faith, fraud, gross negligence or willful misconduct. In addition, we must indemnify MEMP for any liability MEMP incurs as a result of our bad faith or willful misconduct in providing operating and administrative services under the omnibus agreement. We may terminate the omnibus agreement in the event that we cease to be an affiliate of MEMP and may also terminate the omnibus agreement in the event of MEMP s material breach of the agreement, including failure to pay amounts due thereunder in accordance with its terms.

Under the omnibus agreement, none of the parties thereto nor any of their respective affiliates have any obligation to offer, or provide any opportunity to pursue, purchase or invest in, any business opportunity to any other party or their affiliates. Furthermore, the omnibus agreement does not restrict any of the parties thereto and their respective affiliates from competing with either us, MEMP or MEMP s general partner.

Beta Management Agreement

On December 12, 2012, MRD LLC entered into a management agreement with its wholly-owned subsidiary, Beta Operating Company, LLC, pursuant to which MRD LLC agreed to provide management and administrative oversight with respect to the services provided by such subsidiary under certain operating agreements with a subsidiary of MEMP, in exchange for an annual management fee. In connection with the restructuring transactions, we succeeded to this management agreement and we receive approximately $0.4 million from MEMP annually under that agreement.

Services Agreement

Upon the closing of our initial public offering, we entered into a services agreement with WildHorse Resources and WildHorse Resources Management Company, LLC (WHR Management Company), pursuant to which WHR Management Company agreed to provide operating and administrative services to us for twelve months relating to the Terryville Complex. In exchange for such services, we paid a monthly management fee to WHR Management Company of approximately $1.0 million excluding third party COPAS income credits. In 2014, we paid approximately $6.2 million in aggregate to WHR Management Company in exchange for their services under the services agreement.

The services agreement was terminated effective March 1, 2015. WHR Management Company is a subsidiary of WildHorse Resources II, LLC, an affiliate of the Company. NGP and certain former management members of WildHorse Resources own WildHorse Resources II, LLC.

Gas Processing Agreement and Related Agreements

On April 14, 2015, we, through our wholly-owned subsidiary, MRD Operating, entered into an amended and restated gas processing agreement (GPA) with PennTex North Louisiana Operating, LLC (PennTex Operating), a wholly-owned subsidiary of PennTex North Louisiana LLC (PennTex). WildHorse Resources, which owned the Company s interest in the Terryville Complex and merged into MRD Operating in February 2015, initially entered into a gas processing agreement with PennTex in March 2014, prior to the Company s initial public offering. PennTex is a joint venture among certain affiliates of NGP in which MRD Midstream owns a minority interest. Once PennTex s first processing plant becomes operational, it will process natural gas produced from wells located on certain leases owned by us in the state of Louisiana. The agreement has a 15-year primary term, subject to one-year extensions at either party s election. We will pay PennTex a monthly volume processing fee, subject to annual inflation escalators, based on volumes of natural gas processed by PennTex Operating. Once the first plant is declared operational, we will be obligated to pay a minimum processing fee equal to approximately $18.3 million on an annual basis, subject to certain adjustments and conditions until the second processing plant is declared operational. Once the second plant is declared operational, we will be obligated to pay a minimum volume processing fee equal to approximately $55.0 million on an annual basis, subject to certain adjustments and conditions.

In addition, we entered into (i) an amended and restated area of mutual interest and midstream exclusivity agreement (AMI) with PennTex NLA Holdings, LLC, which owns a majority interest in PennTex, MRD WHR LA Midstream LLC, an affiliate of MRD Holdco, and PennTex, (ii) a gas transportation agreement (GTA) with PennTex Operating, (iii) a gas gathering agreement (GGA) with PennTex Operating, and (iv) a transportation services agreement (TSA and, together with the GPA, AMI, GTA and GGA, the Midstream Agreements) with PennTex Operating to provide gathering, residue gas and natural gas liquids transportation services to us in the state of Louisiana. The Midstream Agreements have a 15-year primary term, subject to one-year extensions at either party s election.

Under the GGA, once the first processing plant is declared operational, we will pay PennTex Operating a commodity usage charge equal to at least the minimum volume commitment (115,000 MMBtu per day) times $0.02 per MMBtu until PennTex Operating s second processing plant is declared operational. Once the second processing plant is declared operational, we will pay PennTex Operating a commodity usage charge equal to at least an increased minimum volume commitment (345,000 MMBtu per day) times $0.02 MMBtu through November 30, 2019. The minimum volume commitment will increase to 460,000 MMBtu on July 1, 2016 and may further increase subject to the terms of the GGA. Prior to December 1, 2019, PennTex Operating is also entitled to a payback demand fee from us equal to the monthly demand quantity (460,000 MMBtu per day) times $0.03 MMBtu through November 30, 2019. Beginning on December 1, 2019, PennTex Operating is not entitled to a monthly demand charge, the commodity usage charge escalates to $0.05 per MMBtu, and PennTex Operating is entitled to receive a commodity usage charge from us equal to the minimum volume commitment (460,000 MMBtu per day through June 30, 2019, and 345,000 MMBtu per day thereafter) times $0.05 MMBtu.

Similarly, under each of the GTA and TSA, which commence concurrently with the operational dates of the two processing plants, PennTex Operating will be entitled to a commodity usage charge of $0.04 per MMBtu for all volumes of residue gas and natural gas liquids produced on our behalf.

Under the AMI, we granted PennTex Operating the exclusive right to build all of our midstream infrastructure in northern Louisiana and to provide midstream services to support our current and future production on its operated acreage within such area (other than production subject to existing third-party commitments).

Classic Pipeline Gas Gathering Agreement & Water Disposal Agreement

On November 1, 2011, Classic Hydrocarbons Operating, LLC (Classic Operating) and Classic Pipeline & Gathering, LLC (Classic Pipeline), a subsidiary of MRD Holdco, entered into a gas gathering agreement.

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Pursuant to the gas gathering agreement, Classic Operating dedicated to Classic Pipeline all of the natural gas produced (up to 50,000 MMBtus per day) on the properties operated by Classic Operating within certain counties in Texas through 2020, subject to one-year extensions at either party s election. On May 1, 2014, Classic Operating and Classic Pipeline amended the gas gathering agreement with respect to Classic Operating s remaining assets located in Panola and Shelby Counties, Texas. Under the amended gas gathering agreement, Classic Operating agreed to pay a fee of (i) $0.30 per MMBtu, subject to an annual 3.5% inflationary escalation, based on volumes of natural gas delivered and processed, and (ii) $0.07 per MMBtu per stage of compression plus its allocated share of compressor fuel. The amended gas gathering agreement has a term until December 31, 2023, subject to one-year extensions at either party s election.

On May 1, 2014, Classic Operating and Classic Pipeline entered into a water disposal agreement. The water disposal agreement has a three-year term, subject to one-year extensions at either party s election. Under the water disposal agreement, Classic Operating agreed to pay a fee of $1.10 per barrel for each barrel of water delivered to Classic Pipeline. In February 2015, Classic sold all of the equity interests owned by it in Classic Operating to Memorial Production Operating LLC and Classic was merged into MRD Operating in March 2015. For more information, see Summary Corporate History and Structure.

Repurchase of Net Profits Interests

On February 28, 2014, WildHorse Resources repurchased net profits interests from an affiliate of NGP for $63.4 million after customary adjustments. These net profits interests were originally sold to the NGP affiliate upon the completion of certain acquisitions in 2010 by WildHorse Resources. WildHorse Resources was merged into MRD Operating in February 2015. For more information, see Summary Corporate History and Structure.

Dispositions of Oil and Natural Gas Producing Properties to the Partnership

We have divested long-lived producing oil and natural gas properties to the Partnership through the following drop down transactions since January 1, 2014:

- In April 2014, we sold approximately 15 Bcfe of proved reserves located in East Texas to the Partnership for cash consideration of approximately $33.3 million, including estimated customary post-closing adjustments.

- In October 2014, we sold 4.7 Bcfe of proved reserves located in Weld County, Colorado to the Partnership for cash consideration of approximately $15.0 million.

- In February 2015, we exchanged our East Texas and non-core Louisiana oil and gas properties for all of MEMP s non-operating interests in the Terryville Complex and approximately $78.0 million in cash.

Procedures for Approval of Related Party Transactions

We maintain a policy for approval of related party transactions. A related party transaction is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any related person had, has or will have a direct or indirect material interest. A related person means:

any person who is, or at any time during the applicable period was, one of our executive officers or one of our directors;

any person who is known by us to be the beneficial owner of more than 5% of our common stock;

any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, executive officer or a beneficial owner of more than 5% of our common stock, and any person (other than a tenant or employee) sharing the household of such director, executive officer or beneficial owner of more than 5% of our common stock; and

- any firm, corporation or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10% or greater beneficial ownership interest.

The policy and procedures for reviewing related party transactions are not formally stated, but they are derived from the Code of Conduct and the charter of the Audit Committee. Under its charter, the Audit Committee is responsible for reviewing all material facts of all related party transactions, including transactions for which disclosure would be required under Item 404(a) of Regulation S-K.

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DESCRIPTION OF OTHER INDEBTEDNESS

Senior Secured Revolving Credit Facility

On June 18, 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 an initial borrowing base of $725 million and aggregate elected commitments of $725 million. As of April 13, 2015, the borrowing base under the senior secured revolving credit facility was $725 million.

We are permitted to borrow under the senior secured revolving credit facility in an amount up to the least of (i) the face amount of our revolving credit facility, (ii) the borrowing base and (iii) the aggregate elected commitments. The senior secured revolving credit facility is reserve-based, and thus our borrowing base is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. Our borrowing base is subject to redetermination on a semi-annual basis based on an engineering report with respect to our estimated oil, NGL and natural gas reserves, which will take into account the prevailing oil, NGL 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. In addition, we may, subject to certain conditions, increase our aggregate elected commitments in an amount not to exceed the then effective borrowing base on or following a scheduled redetermination of our borrowing base once before the next scheduled redetermination date. 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.

Borrowings under the senior secured revolving credit facility are secured by liens on substantially all of our properties, but in any event, not less than 80% of the total value of our oil and natural gas properties, and all of our equity interests in any future guarantor subsidiaries and all of our other assets including personal property. Additionally, borrowings bear interest, at our option, at either (i) the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus 0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the total commitment usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the total commitment usage. The unused portion of the total commitments is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to our total commitments usage.

The senior secured revolving credit facility requires maintenance of a ratio of Consolidated EBITDAX to Consolidated Net Interest Expense (as each term is determined under the senior secured revolving credit facility), which we refer to as the interest coverage ratio, of not less than 2.5 to 1.0, and a ratio of consolidated current assets to consolidated current liabilities, each as determined under the senior secured revolving credit facility, which we refer to as the current ratio, of not less than 1.0 to 1.0.

Additionally, the senior secured revolving credit facility contains various covenants and restrictive provisions that, among other things, limit our ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production and prepay certain indebtedness.

Events of default under the senior secured revolving credit facility include, but are not limited to, failure to make payments when due, breach of any covenants continuing beyond the cure period, default under any other material debt, change in management or change of control, bankruptcy or other insolvency event and certain material adverse effects on our business.

If we fail to perform our obligations under these and other covenants, the revolving credit commitments could be terminated and any outstanding indebtedness under the senior secured revolving credit facility, together with accrued interest, fees and other obligations under the credit agreement, could be declared immediately due and payable.

MEMP Revolving Credit Facility & Senior Notes

OLLC is a party to a $2.0 billion revolving credit facility, which is guaranteed by MEMP and all of its current and future subsidiaries (other than certain immaterial subsidiaries). As of March 24, 2015, the borrowing base under the revolving credit facility of OLLC is $1.3 billion.

On April 17, 2013, May 23, 2013 and October 10, 2013, the MEMP Issuers completed a private placement of $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 were issued at 98.521% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of the 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 are governed by an indenture. The 2021 Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The MEMP Issuers may also be required to repurchase the 2021 Senior Notes upon a change of control. 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 2021 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, all outstanding 2021 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 2021 Senior Notes may declare all the 2021 Senior Notes to be due and payable immediately.

On July 17, 2014, the MEMP Issuers completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes (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, commencing on February 1, 2015. The indenture governing the 2022 Notes, dated as July 17, 2014, 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, 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.

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DESCRIPTION OF NOTES

You can find the definitions of certain terms used in this description under the subheading Certain Definitions. In this description, the Company refers only to Memorial Resource Development Corp. and not to any of its Subsidiaries. References to the notes in this section of the prospectus include both the notes issued on July 10, 2014, which we refer to as the old notes, and the new notes offered hereby, unless the context otherwise requires.

The Company will issue the new notes, and did issue the old notes, under an indenture dated as of July 10, 2014, among the Company, the Guarantors and U.S. Bank National Association, as trustee. The terms of the notes include those stated in the indenture and those made part of the indenture by reference to the Trust Indenture Act.

The following description is a summary of the material provisions of the indenture. It does not restate the indenture in its entirety. We urge you to read the indenture because it, and not this description, defines your rights as holders of the notes. A copy of the indenture is filed as an exhibit to the registration statement of which this prospectus is a part. Certain defined terms used in this description but not defined below under Certain Definitions have the meanings assigned to them in the indenture.

The registered holder of a note will be treated as the owner of it for all purposes. Only registered holders have rights under the indenture and all references to holders in this description are to registered holders of notes.

If the exchange offer contemplated by this prospectus is consummated, holders of old notes who do not exchange those notes for new notes in the exchange offer will vote together with holders of new notes for all relevant purposes under the indenture. In that regard, the indenture requires that certain actions by the holders thereunder must be taken, and certain rights must be exercised, by specified minimum percentages of the aggregate principal amount of the outstanding securities issued under the indenture. In determining whether holders of the requisite percentage in principal amount have given any notice, consent or waiver or taken any other action permitted under the indenture, any old notes that remain outstanding after the exchange offer will be aggregated with the new notes and the holders of such old notes and the new notes will vote together as a single class for all such purposes. Accordingly, all references herein to specified percentages in aggregate principal amount of the notes outstanding shall be deemed to mean, at any time after the exchange offer is consummated, such percentages in aggregate principal amount of the old notes and the new notes then outstanding.

Brief Description of the Notes and the Note Guarantees

The New Notes

Like the old notes, the new notes will be:

- general unsecured obligations of the Company;
- *pari passu* in right of payment with all existing and future senior Indebtedness of the Company;
- senior in right of payment to any future subordinated Indebtedness of the Company; and

unconditionally guaranteed by the Guarantors on a senior unsecured basis.

However, the new notes, like the old notes, will be effectively subordinated to the Indebtedness and other obligations of the Subsidiaries of the Company that are not Guarantors, including the Company s Unrestricted Subsidiaries. See Risk Factors Risks Related to the Notes The notes and the guarantees are unsecured and effectively subordinated to our and the guarantors existing and future secured indebtedness.

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The New Note Guarantees

Initially, the new notes, like the old notes, will be guaranteed by the Company s Restricted Subsidiaries other than the MLP General Partner. In the future, other Restricted Subsidiaries of the Company that are not Guarantors may be required to guarantee the notes under the circumstances described below under Certain Covenants Additional Note Guarantees.

Each guarantee of the new notes, like each guarantee of the old notes, will be:

- a general unsecured obligation of the Guarantor;
- *pari passu* in right of payment with all existing and future senior Indebtedness of that Guarantor; and
- senior in right of payment to any future subordinated Indebtedness of that Guarantor.

However, the notes will not be guaranteed by the MLP General Partner, which will be a Restricted Subsidiary, or by the MLP or its Subsidiaries, which will be Unrestricted Subsidiaries. Accordingly, the notes will be effectively subordinated to the Indebtedness and other obligations of the Subsidiaries of the Company that are not Guarantors. See Risk Factors Risks Relating to the Notes The notes and the guarantees are unsecured and effectively subordinated to our and the guarantors existing and future secured indebtedness. Currently, all of the Company s Subsidiaries will be Restricted Subsidiaries other than the MLP and its Subsidiaries. However, under the circumstances described below under the caption Certain Covenants Designation of Restricted and Unrestricted Subsidiaries, the Company will be permitted to designate certain other of its Subsidiaries as Unrestricted Subsidiaries. The Company s Unrestricted Subsidiaries will not be subject to many of the restrictive covenants in the indenture and will not guarantee the notes.

Principal, Maturity and Interest

The Company has issued $600.0 million in aggregate principal amount of old notes. In addition to the new notes offered hereby, the Company may issue additional notes under the indenture from time to time. Any issuance of additional notes is subject to all of the covenants in the indenture, including the covenant described below under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock. The old notes, the new notes and any additional notes subsequently issued under the indenture will be treated as a single class for all purposes under the indenture, including, without limitation, waivers, amendments, redemptions and offers to purchase; provided, however, that if any such additional notes are not fungible with the notes, such additional notes shall have a different CUSIP number (or other applicable identifying number). Unless expressly stated or the context requires otherwise, references to notes for all purposes of the indenture and this Description of Notes section include any additional notes actually issued. The Company may issue notes only in denominations of $2,000 and integral multiples of $1,000 in excess of $2,000. The notes will mature on July 1, 2022.

Interest on the notes accrues at the rate of 5.875% per annum and is payable semi-annually in arrears on January 1 and July 1, commencing on January 1, 2015. The Company will make each interest payment to the holders of record on the immediately preceding December 15 and June 15.

Interest on the notes will accrue from July 10, 2014 or, if interest has already been paid on the old notes, from the date it was most recently paid. Interest will be computed on the basis of a 360-day year comprised of twelve 30-day months.

If an interest payment date falls on a day that is not a Business Day, the interest payment to be made on such interest payment date will be made, without penalty, on the next succeeding Business Day with the same force and effect as if made on such interest payment date.

Methods of Receiving Payments on the Notes

If a holder of notes has given wire transfer instructions to the Company, the Company will pay all principal of, and interest and premium, if any, on, that holder s notes in accordance with those instructions. All other payments on the notes will be made at the office or agency of the paying agent and registrar within the City and State of New York unless the Company elects to make interest payments by check mailed to the holders at their addresses set forth in the register of holders.

Paying Agent and Registrar for the Notes

The trustee currently acts as paying agent and registrar. The Company may change the paying agent or registrar without prior notice to the holders of the notes, and the Company or any of its Subsidiaries may act as paying agent or registrar.

Transfer and Exchange

A holder may transfer or exchange notes in accordance with the provisions of the indenture. The registrar and the trustee may require a holder, among other things, to furnish appropriate endorsements and transfer documents in connection with a transfer of notes. Holders are required to pay all taxes due on transfer. The Company is not required to transfer or exchange any note selected for redemption. Also, the Company is not required to transfer or exchange any note for a period of 15 days before a selection of notes to be redeemed or between a record date and the next succeeding interest payment date.

Note Guarantees

Like the old notes, the new notes will be guaranteed by all of the Company s Restricted Subsidiaries except the MLP General Partner. In the future, other Restricted Subsidiaries of the Company that are not Guarantors may be required to guarantee the notes under the circumstances described below under Certain Covenants Additional Note Guarantees. These Note Guarantees are joint and several obligations of the Guarantors. The obligations of each Guarantor under its Note Guarantee will be limited as necessary to prevent that Note Guarantee from constituting a fraudulent conveyance under applicable law, although this limitation may not be effective to prevent the Note Guarantees from being voided in bankruptcy. See Risk Factors Risks Relating to the Notes 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. A Guarantor may not sell or otherwise dispose of, in one or a series of related transactions, all or substantially all of its properties or assets to, or consolidate with or merge with or into (whether or not such Guarantor is the surviving Person) another Person, other than the Company or another Guarantor, unless:

(1) immediately after giving effect to such transaction or series of transactions, no Default or Event of Default exists; and

(2) either:

(a) the Person acquiring the properties or assets in any such sale or other disposition or the Person formed by or surviving any such consolidation or merger (if other than the Guarantor) unconditionally assumes all the obligations of that Guarantor under its Note Guarantee and the indenture pursuant to a supplemental indenture or other agreement in form reasonably satisfactory to the trustee; or

(b) such transaction or series of transactions does not violate the Asset Sales provisions of the indenture.

The Note Guarantee of a Guarantor will be released:

(1) in connection with any sale or other disposition of all or substantially all of the properties or assets of that Guarantor, by way of merger, consolidation or otherwise, to a Person that is not (either before or

after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the Asset Sales provisions of the indenture;

(2) in connection with any sale or other disposition of the Capital Stock of that Guarantor to a Person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the Asset Sales provisions of the indenture and the Guarantor ceases to be a Restricted Subsidiary of the Company as a result of the sale or other disposition;

(3) if the Company designates such Guarantor to be an Unrestricted Subsidiary in accordance with the applicable provisions of the indenture;

(4) upon legal defeasance or covenant defeasance as provided below under the caption Legal Defeasance and Covenant Defeasance or upon satisfaction and discharge of the indenture as provided below under the caption Satisfaction and Discharge ;

(5) upon the liquidation or dissolution of such Guarantor provided no Default or Event of Default has occurred that is continuing;

(6) upon such Guarantor consolidating with, merging into or transferring all of its properties or assets to the Company or another Guarantor, and as a result of, or in connection with, such transaction such Guarantor dissolving or otherwise ceasing to exist; or

(7) at such time as such Guarantor ceases to guarantee or otherwise be an obligor with respect to any other Indebtedness of the Company or any other Guarantor in excess of the De Minimis Guaranteed Amount, provided no Event of Default has occurred that is continuing.

See Repurchase at the Option of Holders Asset Sales.

On February 2, 2015, WildHorse Resources LLC was merged into MRD Operating LLC (MRD Operating), with MRD Operating surviving such merger. On February 23, 2015, each of Classic Hydrocarbons, Inc. (CHI) and Classic Operating Co. LLC (COC) were merged into Classic Hydrocarbons Operating, LLC (Classic Operating), with Classic Operating surviving such merger (the Classic Merger). Immediately following the Classic Merger, (i) the administrative agent under the Credit Agreement released each of CHI, COC, Classic Operating, Craton Energy GP III, LLC (Craton GP) and Craton Energy Holdings III, LP (Craton LP) as guarantors under the Credit Agreement and (ii) Classic Hydrocarbons Holdings, L.P. (Classic) sold all of the equity interests owned by it in Classic Operating, Craton GP and Craton LP to Memorial Production Operating LLC (MEMP Operating), thereby releasing the Note Guarantee of each of such entities and automatically and unconditionally releasing and discharging such entities from all of their respective obligations under the indenture, in each case, without any further action on the part of the Trustee or any holder. On March 17, 2015, Classic and Classic Hydrocarbons GP Co, L.L.C. were merged into MRD Operating. As a result of the foregoing transactions, although all of the foregoing entities (other than MEMP Operating) were originally Guarantors, none of such entities (other than MRD Operating) remains a Guarantor except to the extent MRD Operating is a successor thereto.

Optional Redemption

At any time prior to July 1, 2017, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of notes (including, without limitation, additional notes, if any) issued under the indenture, in an amount not greater than the net cash proceeds of one or more Equity Offerings by the Company, upon notice as provided in the indenture, at a redemption price equal to 105.875% of the principal amount of the notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption (subject to the rights of holders of notes on the relevant record date to receive interest on the relevant interest payment date); provided that:

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(1) at least 65% of the aggregate principal amount of notes (including, without limitation, additional notes, if any) originally issued under the indenture (excluding notes held by the Company and its Subsidiaries) remains outstanding immediately after the occurrence of such redemption; and

(2) the redemption occurs within 180 days of the date of the closing of such Equity Offering.

At any time prior to July 1, 2017, the Company may on any one or more occasions redeem all or a part of the notes, upon notice as provided in the indenture, at a redemption price equal to 100% of the principal amount of the notes redeemed, plus the Applicable Premium as of, and accrued and unpaid interest to, the date of redemption, subject to the rights of holders of notes on the relevant record date to receive interest due on the relevant interest payment date.

Except pursuant to the preceding paragraphs and the penultimate paragraph under Repurchase at the Option of Holders Change of Control, the notes will not be redeemable at the Company s option prior to July 1, 2017.

On or after July 1, 2017, the Company may on any one or more occasions redeem all or a part of the notes, upon notice as provided in the indenture, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest, if any, on the notes redeemed to the applicable date of redemption, subject to the rights of holders of notes on the relevant record date to receive interest on the relevant interest payment date, if redeemed during the twelve-month period beginning on July 1 of the years indicated below:

Year	Percentage
2017	104.406%
2018	102.938%
2019	101.469%
2020 and thereafter	100.000%

Mandatory Redemption

The Company is not required to make mandatory redemption or sinking fund payments with respect to the notes. The Company may at any time and from time to time purchase notes in the open market or otherwise, in each case without any restriction under the indenture.

Selection and Notice

If less than all of the notes are to be redeemed at any time, the trustee will select notes for redemption on a pro rata basis (or, in the case of notes issued in global form as discussed under Book-Entry, Delivery and Form, based on a method as DTC or its nominee or successor may require or, where such nominee or successor is the trustee, a method that most nearly approximates pro rata selection as the trustee deems fair and appropriate) unless otherwise required by law or applicable stock exchange or depositary requirements.

The unredeemed portion of any note shall be in authorized denominations. Notices of redemption will be mailed by first class mail at least 30 but not more than 60 days before the redemption date to each holder of notes to be redeemed at its registered address, except that redemption notices may be mailed more than 60 days prior to a redemption date if the notice is issued in connection with a defeasance or covenant defeasance of the notes or a satisfaction and discharge of the indenture. The notice of redemption with respect to the redemption described in the second paragraph under the heading Optional Redemption need not set forth the Applicable Premium but only the manner of calculation thereof. The Company will notify the trustee of the Applicable Premium with respect to any such redemption promptly after the calculation, and the trustee shall not be responsible for such calculation. Notices of redemption, including, without limitation, upon an Equity Offering, may, at the Company s discretion, be subject to one or more conditions precedent, including, without limitation, completion of the related Equity Offering.

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If any note is to be redeemed in part only, the notice of redemption that relates to that note will state the portion of the principal amount of that note that is to be redeemed. A new note in principal amount equal to the unredeemed portion of the original note will be issued in the name of the holder of notes upon cancellation of the original note.

Notes or portions thereof called for redemption without condition will become due on the date fixed for redemption. Unless the Company defaults in the payment of the redemption price, interest will cease to accrue on the notes or portions thereof called for redemption on the applicable redemption date.

Repurchase at the Option of Holders

Change of Control

If a Change of Control occurs, each holder of notes will have the right to require the Company to repurchase all or any part (equal to $2,000 or an integral multiple of $1,000 in excess thereof) of that holder s notes pursuant to a cash tender offer (Change of Control Offer) on the terms set forth in the indenture. In the Change of Control Offer, the Company will offer a payment in cash (***Change of Control Payment***) equal to 101% of the aggregate principal amount of notes repurchased, plus accrued and unpaid interest on the notes repurchased to the date of purchase (the ***Change of Control Purchase Date***), subject to the rights of holders of notes on the relevant record date to receive interest due on the relevant interest payment date. Within 30 days following any Change of Control, the Company will mail a notice to each holder describing the transaction or transactions that constitute the Change of Control and offering to repurchase notes properly tendered prior to the expiration date specified in the notice, which date will be no earlier than 30 days and no later than 60 days from the date such notice is mailed, pursuant to the procedures required by the indenture and described in such notice. The Company will comply with the requirements of Rule 14e-1 under the Exchange Act and any other securities laws and regulations thereunder to the extent those laws and regulations are applicable in connection with the repurchase of the notes as a result of a Change of Control. To the extent that the provisions of any securities laws or regulations conflict with the Change of Control provisions of the indenture, the Company will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations under the Change of Control provisions of the indenture by virtue of such compliance.

Promptly following the expiration of the Change of Control Offer, the Company will, to the extent lawful, accept for payment all notes or portions of notes properly tendered pursuant to the Change of Control Offer. Promptly after such acceptance, the Company will, on the Change of Control Purchase Date:

(1) deposit with the paying agent an amount equal to the Change of Control Payment in respect of all notes or portions of notes properly tendered; and

(2) deliver or cause to be delivered to the trustee the notes properly accepted together with an officers certificate stating the aggregate principal amount of notes or portions of notes being purchased by the Company.

The paying agent will promptly mail to each holder of notes properly tendered the Change of Control Payment for such notes (or, if all the notes are then in global form, make such payment through the facilities of The Depository Trust Company (***DTC***)), and the trustee will promptly authenticate and mail to each holder of certificated notes a new note equal in principal amount to any unpurchased portion of the notes surrendered, if any. The Company will publicly announce the results of the Change of Control Offer on or as soon as practicable after the Change of Control Purchase Date.

The provisions described above that require the Company to make a Change of Control Offer following a Change of Control will be applicable whether or not any other provisions of the indenture are applicable. Except as described above with respect to a Change of Control, the indenture does not contain provisions that permit the holders of the notes to require that the Company repurchase or redeem the notes in the event of a takeover, recapitalization or similar transaction.

The Company will not be required to make a Change of Control Offer upon a Change of Control if (1) a third party makes the Change of Control Offer in the manner, at the time and otherwise in compliance with the requirements set forth in the indenture applicable to a Change of Control Offer made by the Company and purchases all notes properly tendered and not withdrawn under the Change of Control Offer, (2) notice of redemption of all outstanding notes has been given pursuant to the indenture as described above under the caption Optional Redemption, unless and until there is a default in payment of the applicable redemption price or (3) in connection with or in contemplation of any Change of Control, the Company has made an offer to purchase (an ***Alternate Offer***) any and all notes validly tendered at a cash price equal to or higher than the Change of Control Payment and has purchased all notes properly tendered in accordance with the terms of such Alternate Offer. Notwithstanding anything to the contrary contained in the indenture, a Change of Control Offer may be made in advance of a Change of Control, conditioned upon the consummation of such Change of Control, if a definitive agreement is in place for the Change of Control at the time the Change of Control Offer is made.

The definition of Change of Control includes a phrase relating to the direct or indirect sale, lease, transfer, conveyance or other disposition of all or substantially all of the properties or assets of the Company and its Subsidiaries taken as a whole. Although there is a limited body of case law interpreting the phrase substantially all, there is no precise established definition of the phrase under applicable law. Accordingly, the ability of a holder of notes to require the Company to repurchase its notes as a result of a sale, lease, transfer, conveyance or other disposition of less than all of the properties or assets of the Company and its Subsidiaries taken as a whole to another Person or group may be uncertain.

In the event that upon consummation of a Change of Control Offer less than 10% of the aggregate principal amount of the notes (including, without limitation, additional notes, if any) that were originally issued are held by holders other than the Company or Affiliates thereof, the Company will have the right, upon not less than 30 nor more than 60 days prior notice, given not more than 30 days following the purchase pursuant to the Change of Control Offer described above, to redeem all of the notes that remain outstanding following such purchase at a redemption price equal to the Change of Control Payment plus, to the extent not included in the Change of Control Payment, accrued and unpaid interest, if any, on the notes that remain outstanding, to the date of redemption, subject to the rights of holders of notes on the relevant record date to receive interest on the relevant interest payment date.

The provisions under the indenture relative to the Company s obligation to make an offer to repurchase the notes as a result of a Change of Control may be waived or modified or terminated with the consent of the holders of a majority in principal amount of the notes (including, without limitation, additional notes, if any) then outstanding (including consents obtained in connection with a tender offer or exchange offer for the notes) prior to the occurrence of such Change of Control.

Asset Sales

The Company will not, and will not permit any of its Restricted Subsidiaries to, consummate an Asset Sale unless:

(1) the Company (or a Restricted Subsidiary, as the case may be) receives consideration at the time of the Asset Sale at least equal to the Fair Market Value (measured as of the date of the definitive agreement with respect to such Asset Sale) of the assets or Equity Interests issued or sold or otherwise disposed of; and

(2)

(A) at least 75% of the aggregate consideration received in the Asset Sale by the Company or a Restricted Subsidiary and all other Asset Sales since the date of the indenture is in the form of cash or Cash Equivalents or (B) the Fair Market Value of all forms of consideration other than cash or Cash Equivalents since the date of the indenture does not exceed in the aggregate 10% of the Adjusted Consolidated Net Tangible Assets of the Company at the time such Asset Sale is made.

provided, that in the case of an MLP Asset Transfer, in lieu of the requirement in clause (2)(A), the Company, at its election, may meet the following requirements:

(x) at least 50% of the Fair Market Value of the aggregate consideration received by the Company or a Restricted Subsidiary in the MLP Asset Transfer is in the form of cash or Cash Equivalents with the balance of the consideration received by the Company or a Restricted Subsidiary in the MLP Asset Transfer consisting solely of Equity Interests in the MLP; and

(y) no Default (other than a Reporting Default) or Event of Default shall have occurred and be continuing or would occur as a consequence thereof.

For purposes of this provision, each of the following will be deemed to be cash:

(a) any liabilities, as shown on the Company s most recent consolidated balance sheet, of the Company or any Restricted Subsidiary (other than contingent liabilities and liabilities that are by their terms subordinated to the notes or any Note Guarantee) that are assumed by the transferee of any such assets pursuant to a novation or indemnity agreement that releases the Company or such Restricted Subsidiary from or indemnifies against further liability (or in lieu of such absence of liability, the acquiring Person or its parent company agrees to indemnify and hold the Company or such Restricted Subsidiary harmless from and against any loss, liability or cost in respect of such assumed liabilities accompanied by the posting of a letter of credit (issued by a commercial bank that has an Investment Grade Rating) in favor of the Company or such Restricted Subsidiary for the full amount of such liabilities and for so long as such liabilities remain outstanding unless such indemnifying party (or its long term debt securities) shall have an Investment Grade Rating (with no indication of a negative outlook or credit watch with negative implications, in any case, that contemplates such indemnifying party (or its long term debt securities) failing to have an Investment Grade Rating) at the time the indemnity is entered into);

(b) with respect to any Asset Sale of Oil and Gas Properties by the Company or any of its Restricted Subsidiaries where the Company or such Restricted Subsidiary retains an interest in such property, any agreement by the transferee (or an Affiliate thereof) to pay all or a portion of the costs and expenses of the Company or such Restricted Subsidiary related to the exploration, development, completion or production of such properties and activities related thereto;

(c) any securities, notes or other obligations received by the Company or any Restricted Subsidiary from such transferee that are, within 180 days of the Asset Sale, converted by the Company or such Restricted Subsidiary into cash, to the extent of the cash received in that conversion; and

(d) Additional Assets.

Within 360 days after the receipt of any Net Proceeds from an Asset Sale, the Company (or any Restricted Subsidiary) may apply such Net Proceeds at its option to any combination of the following:

(1) to repay, redeem or repurchase any Senior Debt;

(2) to invest in or acquire Additional Assets; or

(3) to make capital expenditures in respect of the Company s or any Restricted Subsidiaries Oil and Gas Business.

The requirement of clause (2) or (3) of the preceding paragraph shall be deemed to be satisfied if a bona fide binding contract committing to make the investment, acquisition or expenditure referred to therein is entered into by the Company (or any Restricted Subsidiary) with a Person other than a Restricted Subsidiary within the time period specified in the preceding paragraph and such Net Proceeds are subsequently applied in accordance with such contract within six months following the date such agreement is entered into.

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Pending the final application of any Net Proceeds, the Company (or any Restricted Subsidiary) may temporarily reduce Indebtedness under any Credit Facility or otherwise expend or invest the Net Proceeds in any manner that is not prohibited by the indenture.

Any Net Proceeds from Asset Sales that are not applied or invested as provided in the second paragraph of this covenant will constitute Excess Proceeds. When the aggregate amount of Excess Proceeds exceeds $25.0 million, within five days thereof, the Company will make an offer (an ***Asset Sale Offer***) to all holders of notes and all holders of other Indebtedness that is *pari passu* with the notes containing provisions similar to those set forth in the indenture with respect to offers to purchase, prepay or redeem with the proceeds of sales of assets to purchase, prepay or redeem, on a pro rata basis (based on principal amounts of notes and *pari passu* Indebtedness (or, in the case of *pari passu* Indebtedness issued with significant original issue discount, based on the accreted value thereof) tendered), the maximum principal amount of notes and such other *pari passu* Indebtedness (plus all accrued interest on the Indebtedness and the amount of all fees and expenses, including premiums, incurred in connection therewith) that may be purchased, prepaid or redeemed out of the Excess Proceeds. The offer price in any Asset Sale Offer will be equal to 100% of the principal amount, plus accrued and unpaid interest, if any, to the date of purchase, prepayment or redemption, subject to the rights of holders of notes on the relevant record date to receive interest due on the relevant interest payment date, and will be payable in cash. If any Excess Proceeds remain after consummation of an Asset Sale Offer, the Company or any Restricted Subsidiary may use those Excess Proceeds for any purpose not otherwise prohibited by the indenture. If the aggregate principal amount of notes tendered in such Asset Sale Offer exceeds the amount of Excess Proceeds allocated to the purchase of notes, the trustee will select the notes to be purchased on a pro rata basis (except that any notes represented by a note in global form will be selected by such method as DTC or its nominee or successor may require or, where such nominee or successor is the trustee, a method that most nearly approximates pro rata selection as the trustee deems fair and appropriate), based on the principal amounts tendered (with such adjustments as may be deemed appropriate by the Company so that only notes in denominations of $2,000, and any integral multiple of $1,000 in excess thereof, will be purchased). Upon completion of each Asset Sale Offer, the amount of Excess Proceeds will be reset at zero. The Company may satisfy the foregoing obligation with respect to any Excess Proceeds by making an Asset Sale Offer prior to the expiration of the relevant 360 day period or with respect to Excess Proceeds of $25.0 million or less.

The provisions under the indenture relative to the Company s obligation to make an offer to repurchase the notes as a result of an Asset Sale may be waived or modified with the written consent of a majority in principal amount of the outstanding notes (including, without limitation, additional notes, if any).

The Company will comply with the requirements of Rule 14e-1 under the Exchange Act and any other securities laws and regulations thereunder to the extent those laws and regulations are applicable in connection with each repurchase of notes pursuant to an Asset Sale Offer. To the extent that the provisions of any securities laws or regulations conflict with the Asset Sales provisions of the indenture, the Company will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations under the Asset Sales provisions of the indenture by virtue of such compliance.

Certain Covenants

Termination of Covenants if Notes Rated Investment Grade

If on any date following the date of the indenture:

(1) the notes are rated Baa3 or better by Moody s and BBB- or better by S&P (or, if either such entity ceases to rate the notes for reasons outside of the control of the Company, the equivalent investment grade credit rating from any other nationally recognized statistical rating organization within the meaning of Section 3(a)(62) of the Exchange Act selected by the Company as a replacement agency);

(2) no Default or Event of Default shall have occurred and be continuing; and

(3) the Company has delivered to the trustee an officers certificate certifying to the foregoing provisions of this paragraph,

then, the Company and its Restricted Subsidiaries will no longer be subject to the provisions of the indenture described below under the following captions in this description of notes:

(a) Repurchase at the Option of Holders Asset Sales ;

(b) Certain Covenants Restricted Payments ;

(c) Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ;

(d) Certain Covenants Liens ;

(e) Certain Covenants Dividend and Other Payment Restrictions Affecting Restricted Subsidiaries ;

(f) clause (4) of the covenant described below under the caption Certain Covenants Merger, Consolidation or Sale of Assets ;

(g) Certain Covenants Transactions with Affiliates ; and

(h) Certain Covenants Designation of Restricted and Unrestricted Subsidiaries.

There can be no assurance that the notes will ever be rated as investment grade or, if such rating is achieved, that such rating will be maintained.

Restricted Payments

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly:

(1) declare or pay any dividend or make any other payment or distribution on account of the Company s or any of its Restricted Subsidiaries Equity Interests (including, without limitation, any payment in connection with any merger or consolidation involving the Company or any of its Restricted Subsidiaries) or to the direct or indirect holders of the Company s or any of its Restricted Subsidiaries Equity Interests in their capacity as such (other than dividends or distributions payable in Equity Interests (other than Disqualified Stock) of the Company and other than dividends or distributions payable to the Company or a Restricted Subsidiary of the Company);

(2) repurchase, redeem or otherwise acquire or retire for value (including, without limitation, in connection with any merger or consolidation involving the Company) any Equity Interests of the Company or any direct or indirect parent of the Company other than through the exchange therefor solely of Equity Interests (other than Disqualified Stock) of the Company and other than any acquisition or retirement for value from, or payment to, the Company or any Restricted Subsidiary of the Company;

(3) make any payment on or with respect to, or repurchase, redeem, defease or otherwise acquire or retire for value any Indebtedness of the Company or any Guarantor that is contractually subordinated to the notes or to any Note Guarantee (excluding (a) any intercompany Indebtedness between or among the Company and any of its Restricted Subsidiaries and (b) the repurchase or other acquisition or retirement for value of any such Indebtedness in anticipation of satisfying a sinking fund or other payment obligation due within one year of the date of such repurchase or other acquisition or retirement for value), except a payment of interest or principal at the Stated Maturity thereof; or

(4) make any Restricted Investment (all such payments and other actions set forth in these clauses (1) through (4) being collectively referred to as ***Restricted Payments***),

unless, at the time of and after giving effect to such Restricted Payment,

(a) no Default (except a Reporting Default) or Event of Default has occurred and is continuing or would occur as a consequence of such Restricted Payment;

(b) the Company would, at the time of such Restricted Payment and after giving pro forma effect thereto as if such Restricted Payment had been made at the beginning of the applicable four-quarter period, have been permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described below under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ; and

(c) such Restricted Payment, together with the aggregate amount of all other Restricted Payments made by the Company and its Restricted Subsidiaries since the Measurement Date (excluding Restricted Payments permitted by clauses (2) through (15) of the next succeeding paragraph), is less than the sum, without duplication, of:

(i) 50% of the Consolidated Net Income of the Company for the period (taken as one accounting period) from October 1, 2013 to the end of the Company s most recently ended fiscal quarter for which internal financial statements are available at the time of such Restricted Payment (or, if such Consolidated Net Income for such period is a deficit, less 100% of such deficit); plus

(ii) 100% of the aggregate net cash proceeds and the Fair Market Value of any Capital Stock of Persons engaged primarily in the Oil and Gas Business or any other assets that are used or useful in the Oil and Gas Business other than cash, in each case received by the Company since the Measurement Date as a contribution to its common equity capital or from the issue or sale of Equity Interests of the Company (other than Disqualified Stock) or received by the Company from the issue or sale of convertible or exchangeable Disqualified Stock or convertible or exchangeable debt securities of the Company that have been converted into or exchanged for such Equity Interests since the Measurement Date or from the issue or sale of options, warrants or rights to purchase such Equity Interests that have been exercised for such Equity Interests since the Measurement Date (other than, in either case, Equity Interests (or Disqualified Stock or debt securities) sold to a Restricted Subsidiary of the Company or to an employee stock ownership plan, option plan or similar trust to the extent such sale to an employee stock ownership plan, option plan or similar trust is financed by loans from or Guaranteed by the Company or any Restricted Subsidiary (unless such loans have been repaid with cash on or prior to the date of determination)); plus

(iii) to the extent not already included in Consolidated Net Income for such period, if any Restricted Investment that was made by the Company or any of its Restricted Subsidiaries after the Measurement Date is sold (other than to the Company or any Restricted Subsidiary of the Company) or otherwise cancelled, liquidated or repaid, 100% of the aggregate cash, and the Fair Market Value of any property other than cash, constituting the return of capital to the Company or any of its Restricted Subsidiaries with respect to such Restricted Investment resulting from such sale, cancellation, liquidation or repayment (less any out-of-pocket costs incurred in connection with any such sale); plus

(iv) the amount by which Indebtedness of the Company or its Restricted Subsidiaries is reduced on the Company s balance sheet upon the conversion or exchange (other than by a Restricted Subsidiary of the Company) subsequent to the Measurement Date of any such Indebtedness of the Company or its Restricted Subsidiaries convertible or exchangeable for Equity Interests (other than Disqualified Stock) of the Company (less the amount of any cash, or the Fair Market Value of any other property (other than such Equity Interests), distributed by the Company upon such conversion or exchange and excluding the net cash proceeds from the conversion or exchange financed, directly or indirectly, using funds borrowed from the Company or any Restricted Subsidiary), together with the net proceeds, if any, received by the Company or any of its Restricted Subsidiaries upon such conversion or exchange; plus

(v) to the extent that any Unrestricted Subsidiary of the Company designated as such after the Measurement Date is redesignated as a Restricted Subsidiary pursuant to the terms of the indenture or is merged or consolidated with or into, or transfers or otherwise disposes of all of substantially all of its properties or assets to or is liquidated into, the Company or a Restricted Subsidiary after the Measurement Date, the lesser of, as of the date of such redesignation, merger, consolidation, transfer, disposition or liquidation, (A) the Fair Market Value of the Company s Restricted Investment in such Subsidiary (or of the properties or assets disposed of, as applicable) as of the date of such redesignation, merger, consolidation, transfer, disposition or liquidation and (B) such Fair Market Value as of the date on which such Subsidiary was originally designated as an Unrestricted Subsidiary after the Measurement Date; plus

(vi) the amount equal to the net reduction in Restricted Investments made since the Measurement Date resulting from dividends, distributions, redemptions or repurchases, proceeds of sales or other dispositions thereof, interest payments, repayments of loans or advances, releases of guarantees or other transfers of assets (including transfers as a result of a merger or liquidation), in each case to the Company or any of its Restricted Subsidiaries from any Person (including, without limitation, Unrestricted Subsidiaries) in respect of Restricted Investments; plus

(vii) to the extent not included in clause (vi), any dividends received in cash by the Company or any of its Restricted Subsidiaries since the Measurement Date from an Unrestricted Subsidiary, to the extent such dividends were not otherwise included in the Consolidated Net Income of the Company for such period.

The preceding provisions will not prohibit any of the following actions:

(1) the payment of any dividend or the consummation of any irrevocable redemption within 60 days after the date of declaration of the dividend or giving of the redemption notice, as the case may be, if at the date of declaration or notice, the dividend or redemption payment would have complied with the provisions of the indenture;

(2) the making of any Restricted Payment in exchange for, or out of or with the net cash proceeds of the substantially concurrent sale (other than to a Subsidiary of the Company) of, Equity Interests of the Company (other than Disqualified Stock) or from the substantially concurrent contribution of common equity capital to the Company; provided that the amount of any such net cash proceeds that are utilized for any such Restricted Payment will not be considered to be net proceeds of Equity Interests for purposes of clause (c)(ii) of the preceding paragraph and will not be considered to be net cash proceeds from an Equity Offering for purposes of the Optional Redemption provisions of the indenture;

(3) the payment of any dividend (or, in the case of any partnership or limited liability company, any similar distribution) by a Restricted Subsidiary of the Company to the holders of its Equity Interests on a pro rata basis (or a basis more favorable to the Company);

(4) the repurchase, redemption, defeasance, satisfaction and discharge or other acquisition or retirement for value of Indebtedness of the Company or any Guarantor that is contractually subordinated to the notes or to any Note Guarantee or any Disqualified Stock of the Company out or with the net cash proceeds from a substantially concurrent incurrence of, or in exchange for, Permitted Refinancing Indebtedness;

(5) the repurchase, redemption or other acquisition or retirement for value of any Equity Interests of the Company or any Restricted Subsidiary of the Company held by any current or former officer, director or employee of the Company or any of its Restricted Subsidiaries pursuant to any equity subscription agreement, equity option agreement, unitholders agreement or similar agreement; *provided* that the aggregate price paid for all such repurchased, redeemed, acquired or retired Equity Interests may not exceed $15.0 million in any calendar year (with any portion of such $15.0 million amount that is

unused in any calendar year to be carried forward to successive calendar years and added to such amount), plus (a) the cash proceeds received by the Company or any of its Restricted Subsidiaries from sales of Equity Interests of the Company to employees or directors of the Company that occur after the Measurement Date (to the extent the cash proceeds from the sale of such Equity Interests have not otherwise been applied to the payment of Restricted Payments by virtue of clause (c)(ii) of the preceding paragraph), plus (b) the cash proceeds of key man life insurance policies received by the Company or any of its Restricted Subsidiaries after the Measurement Date, less (c) the amount of payments previously effected by using amounts specified in the foregoing clauses (a) and (b);

(6) loans or advances to employees of the Company or employees or directors of any Subsidiary of the Company, in each case as permitted by Section 402 of the Sarbanes-Oxley Act of 2002, the proceeds of which are used to purchase Capital Stock of the Company, or to refinance loans or advances made pursuant to this clause (6), in an aggregate amount not in excess of $5.0 million at any one time outstanding;

(7) the repurchase or other acquisition or retirement for value of Equity Interests deemed to occur upon the exercise, conversion or exchange of units or other equity options, warrants, incentives or other rights to acquire Equity Interests to the extent such Equity Interests represent a portion of the exercise, conversion or exchange price of those unit or other equity options or other rights and any repurchase or other acquisition or retirement for value of Equity Interests made in lieu of withholding taxes in connection with any exercise, conversion or exchange of units or other equity options, warrants, incentives or other rights to acquire Equity Interests;

(8) the repurchase, redemption or other acquisition or retirement for value of Equity Interests of the Company or any Restricted Subsidiary of the Company representing fractional units of such Equity Interests in connection with a merger or consolidation involving the Company or such Restricted Subsidiary or any other transaction permitted by the indenture;

(9) any payments in connection with a consolidation, merger or transfer of assets in connection with a transaction that is not prohibited by the indenture not to exceed $10.0 million in the aggregate after the Measurement Date;

(10) the declaration and payment of regularly scheduled or accrued dividends to holders of any class or series of Disqualified Stock of the Company or any Preferred Stock of any Restricted Subsidiary of the Company issued on or after the Measurement Date in accordance with the covenant described below under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ;

(11) payments of cash, dividends, distributions, advances or other Restricted Payments by the Company or any of its Restricted Subsidiaries to allow the payment of cash in lieu of the issuance of fractional units upon (i) the exercise of options or warrants, incentives or other rights to acquire Equity Interests or (ii) the exercise, conversion or exchange of Equity Interests of any such Person;

(12) the purchase, redemption or other acquisition or retirement for value of Indebtedness that is subordinated or junior in right of payment to the notes or any Note Guarantee at a purchase price not greater than (i) 101% of the principal amount of such subordinated or junior Indebtedness in the event of a Change of Control or (ii) 100% of the principal amount of such subordinated or junior Indebtedness in the event of an Asset Sale, in each case, plus accrued and unpaid interest thereon, in connection with any change of control offer or prepayment offer required by the terms of such Indebtedness, but only if:

(a) in the case of a Change of Control, the Company has first complied with and fully satisfied its obligations described under the caption Repurchase at the Option of Holders Change of Control ; or

(b) in the case of an Asset Sale, the Company has complied with and fully satisfied its obligations in accordance with the covenant described under the caption Repurchase at the Option of Holders Asset Sales ;

(13) so long as the Company is a pass-through entity for U.S. federal income tax purposes, Permitted Tax Distributions;

(14) the payment in December 2013 of up to $220 million as a dividend or distribution to the Company s equity holders using the net proceeds of the PIK Notes; and

(15) any Restricted Payment, which when combined with the outstanding amount of all other Restricted Payments effected pursuant to this clause (15) after the Measurement Date, does not exceed $50.0 million.

The amount of all Restricted Payments (other than cash) will be the Fair Market Value, on the date of the Restricted Payment, of the Restricted Investment proposed to be made or the asset(s) or securities proposed to be transferred or issued by the Company or any of its Restricted Subsidiaries, as the case may be, pursuant to the Restricted Payment, except that the Fair Market Value of any non-cash dividend paid within 60 days after the date of declaration will be determined as of such date of declaration. The Fair Market Value of any Restricted Investment, assets or securities that are required to be valued by this covenant will be determined in accordance with the definition of that term. For purposes of determining compliance with this Restricted Payments covenant, in the event that a Restricted Payment (or payment or other transaction that, except for being a Permitted Investment or Permitted Payment, would constitute a Restricted Payment) meets the criteria of more than one of the categories of Restricted Payments described in the preceding clauses (1) through (15) of this covenant, or is permitted pursuant to the first paragraph of this covenant or is a Permitted Investment or Permitted Payment, the Company will be permitted to classify (or later classify or reclassify in whole or in part in its sole discretion) such Restricted Payment or other such transaction (or portion thereof) on the date made or later reclassify such Restricted Payment or other such transaction (or portion thereof) in any manner that complies with this covenant. ***Permitted Payment*** means any transaction expressly excluded from clauses (1), (2) and (3) of the first paragraph of this covenant.

For purposes of this covenant and the definition of Permitted Investments, a contribution, sale or incurrence will be deemed to be substantially concurrent if the related Restricted Payment or purchase, repurchase, redemption, defeasance, satisfaction and discharge, retirement or other acquisition for value or payment of principal or acquisition of assets or Capital Stock occurs within 180 days before or after such contribution, sale or incurrence. For purposes of this covenant, references to the Company include MRD LLC.

Incurrence of Indebtedness and Issuance of Preferred Stock

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create, incur, issue, assume, Guarantee or otherwise become directly or indirectly liable, contingently or otherwise, with respect to (collectively, incur) any Indebtedness (including Acquired Debt), and the Company will not issue any Disqualified Stock and will not permit any of its Restricted Subsidiaries to issue any Preferred Stock; *provided*, *however*, that the Company may incur Indebtedness (including Acquired Debt) or issue Disqualified Stock, and the Company s Restricted Subsidiaries may incur Indebtedness (including Acquired Debt) or issue Preferred Stock, if the Fixed Charge Coverage Ratio for the Company s most recently ended four full fiscal quarters for which internal financial statements are available immediately preceding the date on which such additional Indebtedness is incurred or such Disqualified Stock or such Preferred Stock is issued, as the case may be, would have been at least 2.0 to 1.0, determined on a pro forma basis (including a pro forma application of the net proceeds therefrom), as if the additional Indebtedness had been incurred or the Disqualified Stock or the Preferred Stock had been issued, as the case may be, at the beginning of such four-quarter period.

The first paragraph of this covenant will not prohibit the incurrence of any of the following items of Indebtedness or issuances of Disqualified Stock or Preferred Stock, as applicable (collectively, ***Permitted Debt***):

(1) the incurrence by the Company or any Restricted Subsidiary (whether as borrower or guarantor) of Indebtedness and letters of credit under one or more Credit Facilities in an aggregate principal amount

at any one time outstanding under this clause (1) (with letters of credit being deemed to have a principal amount equal to the maximum potential liability of the Company and its Restricted Subsidiaries thereunder) not to exceed the greater of (i) $725.0 million and (ii) the sum of (x) $400.0 million and (y) 35.0% of Adjusted Consolidated Net Tangible Assets determined on the date of such incurrence;

(2) the incurrence by the Company and its Restricted Subsidiaries of the Existing Indebtedness;

(3) the incurrence by the Company and the Guarantors of Indebtedness represented by (a) the notes that were issued on the date of the indenture; (b) the Exchange Notes issued pursuant to any registration rights agreement; and (c) any Note Guarantees;

(4) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness represented by Capital Lease Obligations, mortgage financings or purchase money obligations or other Indebtedness, in each case, incurred for the purpose of financing all or any part of the purchase price or other acquisition cost or cost of design, construction, installation, development, repair or improvement of property, plant or equipment used in the business of the Company or any of its Restricted Subsidiaries (together with improvements, additions, accessions and contractual rights relating primarily thereto), and any Permitted Refinancing Indebtedness incurred to renew, refund, refinance, replace, defease or discharge any Indebtedness incurred pursuant to this clause (4), in an aggregate principal amount, when taken together with the outstanding amount of all other Indebtedness or Permitted Refinancing Indebtedness incurred pursuant to this clause (4), not to exceed the greater of (a) $75.0 million and (b) 7.5% of Adjusted Consolidated Net Tangible Assets determined at the date of such incurrence;

(5) the incurrence by the Company or any of its Restricted Subsidiaries of Permitted Refinancing Indebtedness in exchange for, or the net proceeds of which are used to renew, refund, refinance, replace, defease or discharge any Indebtedness (other than intercompany Indebtedness) or Disqualified Stock or Preferred Stock that was permitted by the indenture to be incurred under the first paragraph of this covenant or clause (2), (3), (5), (15) or (17) of this paragraph;

(6) the incurrence by the Company or any of its Restricted Subsidiaries of intercompany Indebtedness between or among the Company and any of its Restricted Subsidiaries; *provided*, *however*, that:

(a) if the Company or any Guarantor is the obligor on such Indebtedness and the payee is not the Company or a Guarantor, such Indebtedness must be unsecured and expressly subordinated to the prior payment in full in cash of all Obligations then due with respect to the notes, in the case of the Company, or the Note Guarantee, in the case of a Guarantor; and

(b) (i) any subsequent issuance or transfer of Equity Interests that results in any such Indebtedness being held by a Person other than the Company or a Restricted Subsidiary of the Company and (ii) any sale or other transfer of any such Indebtedness to a Person that is not either the Company or a Restricted Subsidiary of the Company, will be deemed, in each case, to constitute an incurrence of such Indebtedness by the Company or such Restricted Subsidiary, as the case may be, that was not permitted by this clause (6);

(7) the issuance by any of the Company s Restricted Subsidiaries to the Company or to any of its Restricted Subsidiaries of any Preferred Stock; *provided*, *however*, that:

(a) any subsequent issuance or transfer of Equity Interests that results in any such Preferred Stock being held by a Person other than the Company or a Restricted Subsidiary of the Company; and

(b) any sale or other transfer of any such Preferred Stock to a Person that is not either the Company or a Restricted Subsidiary of the Company,

will be deemed, in each case, to constitute an issuance of such Preferred Stock by such Restricted Subsidiary that was not permitted by this clause (7);

(8) the incurrence by the Company or any of its Restricted Subsidiaries of Hedging Obligations that are customary in the Oil and Gas Business and not for speculative purposes;

(9) the Guarantee by the Company or any of the Guarantors of Indebtedness of the Company or a Restricted Subsidiary of the Company to the extent that the guaranteed Indebtedness was permitted to be incurred by another provision of this covenant; *provided* that if the Indebtedness being guaranteed is subordinated to or pari passu with the notes, then the Guarantee must be subordinated or *pari passu*, as applicable, to the same extent as the Indebtedness guaranteed, and if the Guarantee is by a Restricted Subsidiary that is not a Guarantor, the Indebtedness guaranteed could have otherwise been incurred by such Restricted Subsidiary under this covenant;

(10) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness in respect of self-insurance obligations or bid, plugging and abandonment, appeal, reimbursement, performance, surety and similar bonds and completion guarantees issued or provided by, or for the account of, the Company or a Restricted Subsidiary in the ordinary course of business and any Guarantees or obligations with respect to letters of credit functioning as or supporting any of the foregoing bonds or obligations and workers compensation claims in the ordinary course of business;

(11) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument inadvertently drawn against insufficient funds, so long as such Indebtedness is covered within five Business Days;

(12) the incurrence by the Company or any of its Restricted Subsidiaries of in-kind obligations relating to net oil or natural gas balancing positions arising in the ordinary course of business;

(13) the incurrence of any obligation arising from agreements of the Company or any Restricted Subsidiary of the Company providing for indemnification, guarantees (other than guarantees of Indebtedness), adjustment of purchase price, holdbacks, earn outs or similar obligations, in each case, incurred or assumed in connection with the disposition or acquisition of any business, assets or Capital Stock of a Restricted Subsidiary in a transaction permitted by the indenture, *provided* such obligation is not reflected on the face of the balance sheet of the Company or any Restricted Subsidiary;

(14) the incurrence by the Company or any of its Restricted Subsidiaries of liability in respect of Indebtedness of any Unrestricted Subsidiary of the Company or any Joint Venture but only to the extent that such liability is the result of (a) the Company s or any such Restricted Subsidiary s being a general partner or member of, or owner of an Equity Interest in, such Unrestricted Subsidiary or Joint Venture and not as guarantor of such Indebtedness and *provided* that after giving effect to any such incurrence, the aggregate principal amount of all Indebtedness incurred under this clause (14)(a) and then outstanding does not exceed the greater of (i) $50.0 million and (ii) 5.0% of Adjusted Consolidated Net Tangible Assets determined on the date of such incurrence or (b) the pledge of (or a Guaranty limited in recourse solely to) Equity Interests in such Unrestricted Subsidiary or Joint Venture held by the Company or such Restricted Subsidiary to secure such Indebtedness and solely to the extent such Indebtedness constitutes Non-Recourse Debt;

(15) the incurrence by the Company or its Restricted Subsidiaries of Permitted Acquisition Indebtedness;

(16) the incurrence by the Company or its Restricted Subsidiaries of Indebtedness consisting of the financing of insurance premiums in customary amounts consistent with the operations and business of the Company and the Restricted Subsidiaries; and

(17) the incurrence by the Company or any Restricted Subsidiary of additional Indebtedness or the issuance by the Company of any Disqualified Stock or by any Restricted Subsidiary of Preferred Stock in an aggregate principal amount, when taken together with the outstanding amount of all other Indebtedness incurred or Disqualified Stock or Preferred Stock issued pursuant to this clause (17), not to exceed the greater of (i) $100.0 million and (ii) 5.0% of Adjusted Consolidated Net Tangible Assets determined on the date of such incurrence or issuance.

The Company will not incur, and will not permit any Guarantor to incur, any Indebtedness (including Permitted Debt) that is contractually subordinated in right of payment to any other Indebtedness of the Company or such Guarantor unless such Indebtedness is also contractually subordinated in right of payment to the notes or the applicable Note Guarantee on substantially identical terms; *provided, however*, that no Indebtedness will be deemed to be contractually subordinated in right of payment to any other Indebtedness of the Company or any Guarantor solely by virtue of being unsecured or not having the benefit of a Lien on assets, or guarantee of a Person, that benefits the other Indebtedness or having the benefit of such a Lien or guarantee ranking subordinate or junior to a Lien or guarantee benefitting the other Indebtedness.

Indebtedness permitted by this covenant need not be permitted solely by reference to one provision permitting such Indebtedness or Disqualified Stock or Preferred Stock but may be permitted in part by one such provision and in part by one or more other provisions of this covenant permitting such Indebtedness or Disqualified Stock or Preferred Stock. For purposes of determining compliance with this Incurrence of Indebtedness and Issuance of Preferred Stock covenant, in the event that an item of Indebtedness or Disqualified Stock or Preferred Stock meets the criteria of more than one of the categories of Permitted Debt described in clauses (1) through (17) above, or is entitled to be incurred pursuant to the first paragraph of this covenant, the Company will be permitted to divide, classify and reclassify such item of Indebtedness or Disqualified Stock or Preferred Stock on the date of its incurrence or issuance, or later redivide or reclassify all or a portion of such item of Indebtedness or Disqualified Stock or Preferred Stock, in any manner (including by dividing and classifying such item of Indebtedness or Disqualified Stock or Preferred Stock in more than one type of Indebtedness or Disqualified Stock or Preferred Stock permitted under such covenant) that complies with this covenant.

The dollar equivalent principal amount of any Indebtedness denominated in a foreign currency and incurred pursuant to any dollar-denominated restriction on the incurrence of Indebtedness shall be calculated based on the relevant exchange rates in effect at the time of incurrence, in the case of term Indebtedness, or first committed, in the case of revolving credit Indebtedness; *provided* that if such Indebtedness is incurred to refinance other Indebtedness denominated in a foreign currency, and such refinancing would cause the applicable U.S. dollar-denominated restriction to be exceeded if calculated at the relevant currency exchange rate in effect on the date of such refinancing, such U.S. dollar-denominated restriction shall be deemed not to have been exceeded so long as the principal amount of such refinancing Indebtedness does not exceed the principal amount of such Indebtedness being refinanced. Notwithstanding any other provision of this covenant, the maximum amount of Indebtedness that the Company and the Restricted Subsidiaries may incur pursuant to this covenant shall not be deemed to be exceeded solely as a result of fluctuations in the exchange rates of currencies. The principal amount of any Indebtedness incurred to refinance other Indebtedness, if incurred in a different currency from the Indebtedness being refinanced, shall be calculated based on the currency exchange rate applicable to the currencies in which such Permitted Refinancing Indebtedness is denominated that is in effect on the date of such refinancing.

The accrual of interest or Preferred Stock dividends, the accretion or amortization of original issue discount, the payment of interest on any Indebtedness not secured by a Lien or on the notes in the form of additional Indebtedness with the same term and the payment of dividends on Preferred Stock or Disqualified Stock in the form of additional securities of the same class of Preferred Stock or Disqualified Stock will not be deemed to be an incurrence of Indebtedness or an issuance of Preferred Stock or Disqualified Stock for purposes of this covenant; *provided* that the amount thereof is included in Fixed Charges of the Company as accrued to the extent required by the definition of such term. For purposes of this covenant, (i) the accrual of an obligation to pay a premium in respect of Indebtedness or Disqualified Stock or Preferred Stock arising in connection with the issuance of a notice of redemption or making of a mandatory offer to purchase such Indebtedness or Disqualified Stock or Preferred Stock, and (ii) unrealized losses or charges in respect of Hedging Agreements (including those resulting from the application of FASB ASC Topic No. 815, *Derivatives and Hedging*) will, in the case of (i) or (ii), not be deemed to be an incurrence of Indebtedness or

Disqualified Stock or Preferred Stock. Further, the accounting reclassification of any obligation or Disqualified Stock or Preferred Stock of the Company or any of

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its Restricted Subsidiaries as Indebtedness or Disqualified Stock or Preferred Stock will not be deemed an incurrence of Indebtedness or issuance of Disqualified Stock or Preferred Stock for purposes of this covenant.

The amount or principal amount of any Indebtedness or Preferred Stock or Disqualified Stock outstanding at any time of determination as used herein shall be as set forth below or, if not set forth below, determined in accordance with GAAP:

(1) the accreted value of the Indebtedness, in the case of any Indebtedness issued with original issue discount;

(2) the principal amount of the Indebtedness, in the case of any other Indebtedness;

(3) in respect of Indebtedness of another Person secured by a Lien on the assets of the specified Person, the lesser of:

(a) the Fair Market Value of such assets at the date of determination; and

(b) the amount of the Indebtedness of the other Person;

(4) in the case of any Capital Lease Obligation, the amount determined in accordance with the definition thereof;

(5) in the case of any Preferred Stock, (x) if other than Disqualified Stock, the greater of its voluntary or involuntary liquidation preference and its maximum fixed redemption price or repurchase price or (y) if Disqualified Stock, as specified in the definition thereof;

(6) in the case of any Interest Rate Agreements included in the definition of Permitted Debt, zero;

(7) in the case of all other unconditional obligations, the amount of the liability thereof determined in accordance with GAAP; and

(8) in the case of all other contingent obligations, the maximum liability at such date of such Person.

For purposes of determining any particular amount of Indebtedness, (i) guarantees of, or obligations in respect of letters of credit relating to, Indebtedness otherwise included in the determination of such amount shall not also be included and (ii) if obligations in respect of letters of credit are incurred pursuant to a Credit Facility and are being treated as incurred pursuant to clause (1) of the definition of Permitted Debt and the letters of credit relate to other Indebtedness, then the amount of such other Indebtedness equal to the face amount of such letters of credit shall not be included. If Indebtedness is secured by a letter of credit that serves only to secure such Indebtedness, then the total amount deemed incurred shall be equal to the greater of (x) the principal of such Indebtedness and (y) the amount that may be drawn under such letter of credit.

Liens

The Company will not and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create, incur, assume or otherwise cause or suffer to exist or become effective any Lien of any kind (other than Permitted Liens) securing Indebtedness upon any of their property or assets, now owned or hereafter acquired, unless the notes or any Note Guarantee of such Restricted Subsidiary, as applicable, are secured on an equal and ratable basis with the Indebtedness so secured (or, in the case of Indebtedness subordinated to the notes or any Note Guarantee, prior or senior thereto, with the same relative priority as the notes or Note Guarantee shall have with respect to such subordinated Indebtedness) until such time as such Indebtedness is no longer secured by a Lien. Any Lien created for the benefit of the holders of the notes pursuant to the preceding sentence shall provide by its terms that such Lien shall be automatically and unconditionally released and discharged upon the release and discharge of the initial Lien, *provided* no Event of Default has occurred and is continuing at the time of such release and discharge.

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Dividend and Other Payment Restrictions Affecting Restricted Subsidiaries

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create or permit to exist or become effective any consensual encumbrance or restriction on the ability of any Restricted Subsidiary to:

(1) pay dividends or make any other distributions on its Capital Stock to the Company or any of its Restricted Subsidiaries, or pay any indebtedness owed to the Company or any of its Restricted Subsidiaries; *provided* that (i) the priority that any series of Preferred Stock of a Restricted Subsidiary has in receiving dividends or liquidating distributions before dividends or liquidating distributions are paid in respect of common stock of such Restricted Subsidiary shall not constitute a restriction on the ability to pay or make dividends or distributions on Capital Stock for purposes of this covenant and (ii) the subordination of indebtedness owed to the Company or any Restricted Subsidiary to other indebtedness incurred by any Restricted Subsidiary shall not be deemed a restriction on the ability to pay indebtedness;

(2) make loans or advances to the Company or any of its Restricted Subsidiaries (it being understood that the subordination of loans or advances made to the Company or any Restricted Subsidiary to other Indebtedness incurred by the Company or any Restricted Subsidiary shall not be deemed a restriction on the ability to make loans or advances); or

(3) sell, lease or transfer any of its properties or assets to the Company or any of its Restricted Subsidiaries.

However, the preceding restrictions will not apply to encumbrances or restrictions existing under or by reason of:

(1) the Credit Agreement as in effect on the date of the indenture and any amendments, restatements, modifications, renewals, supplements, refundings, replacements or refinancings of those agreements; *provided* that the amendments, restatements, modifications, renewals, supplements, refundings, replacements or refinancings are not materially more restrictive, taken as a whole, with respect to such dividend and other payment restrictions than those contained in those agreements on the date of the indenture, as determined in good faith by the Company;

(2) the indenture, the notes and the Note Guarantees;

(3) agreements governing other Indebtedness permitted to be incurred under the provisions of the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock and any amendments, restatements, modifications, renewals, supplements, refundings, replacements or refinancings of those agreements; *provided* that the restrictions therein are not materially more restrictive, taken as a whole, than those contained in the indenture, the notes and the Note Guarantees or the Credit Agreement as in effect on the date of the indenture, as determined in good faith by the Company;

(4) applicable law, rule, regulation, order, approval, license, permit or similar restriction;

(5) any instrument governing Indebtedness or Capital Stock or other agreement of a Person acquired (including by merger or consolidation), or the assets of which are acquired, by the Company or any of its Restricted Subsidiaries as in effect at the time of such acquisition (except to the extent such Indebtedness or Capital Stock or other agreement was incurred in connection with or in contemplation of such acquisition), which encumbrance or restriction is not applicable to any Person, or the properties or assets of any Person, other than the Person, or the property or assets of the Person, so acquired; *provided* that, in the case of Indebtedness, such Indebtedness was permitted by the terms of the indenture to be incurred;

(6) customary non-assignment provisions in Hydrocarbon purchase and sale or exchange agreements or similar operational agreements or in licenses, easements or leases, in each case, entered into in the ordinary course of business;

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(7) purchase money obligations for property acquired in the ordinary course of business and Capital Lease Obligations that impose restrictions on the property purchased or leased of the nature described in clause (3) of the preceding paragraph;

(8) any agreement for the sale or other disposition of a Restricted Subsidiary that restricts distributions by that Restricted Subsidiary pending its sale or other disposition;

(9) Permitted Refinancing Indebtedness; *provided* that the restrictions contained in the agreements governing such Permitted Refinancing Indebtedness are not materially more restrictive, taken as a whole, than those contained in the agreements governing the Indebtedness being refinanced, as determined in good faith by the Company;

(10) Liens permitted to be incurred under the provisions of the covenant described above under the caption Certain Covenants Liens that limit the right of the debtor to dispose of the assets subject to such Liens;

(11) provisions limiting the disposition or distribution of assets or property in joint venture agreements, asset sale agreements, sale-leaseback agreements, stock sale agreements, shareholders agreements, partnership agreements and other similar agreements (including agreements entered into in connection with a Restricted Investment) entered into with the approval of the Board of Directors of the Company or in the ordinary course of business, which limitation is applicable only to the assets or property that is the subject of such agreements;

(12) any agreement or instrument relating to any property or assets acquired after the date of the indenture, so long as such encumbrance or restriction relates only to the property or assets so acquired and is not and was not created in anticipation of such acquisition;

(13) encumbrances or restrictions on cash, Cash Equivalents or other deposits or net worth requirements imposed by customers or lessors under contracts or leases entered into in the ordinary course of business;

(14) any Preferred Stock issued by a Restricted Subsidiary of the Company; *provided* that issuance of such Preferred Stock is permitted pursuant to the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock and the terms of such Preferred Stock do not expressly restrict the ability of a Restricted Subsidiary of the Company to pay dividends or make any other distributions on its Equity Interests (other than requirements to pay dividends or liquidation preferences on such Preferred Stock prior to paying any dividends or making any other distributions on such other Equity Interests);

(15) in the case of any Foreign Subsidiary, any encumbrance or restriction contained in the terms of any Indebtedness or any agreement pursuant to which such Indebtedness was incurred if either (a) the encumbrance or restriction applies only in the event of a payment default or a default with respect to a

financial covenant in such Indebtedness or agreement or (b) any such encumbrance or restriction will not materially affect the Company s ability to make principal or interest payments on the notes, as determined in good faith by the Company;

(16) Oil and Gas Hedging Contracts or Interest Rate Agreements permitted from time to time under the indenture;

(17) encumbrances and restrictions contained in contracts entered into in the ordinary course of business, not relating to any Indebtedness, and that do not, taken as a whole, detract from the value of, or from the ability of the Company and its Restricted Subsidiaries to realize the value of, property or assets of the Company or any Restricted Subsidiary in any manner material to the Company or any Restricted Subsidiary, as determined in good faith by the Company; *provided* that such encumbrances or restrictions will not materially affect the Company s ability to make principal or interest payments on the notes, as determined in good faith by the Company; or

(18) any Permitted Investment.

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Merger, Consolidation or Sale of Assets

The Company will not, directly or indirectly: (x) consolidate or merge with or into another Person (whether or not the Company is the survivor), or (y) sell, assign, transfer, convey, lease or otherwise dispose of all or substantially all of its properties or assets, in one or more related transactions, to another Person, unless:

(1) either: (a) the Company is the surviving Person; or (b) the Person formed by or surviving any such consolidation or merger (if other than the Company) or to which such sale, assignment, transfer, conveyance, lease or other disposition has been made is a Person organized or existing under the laws of the United States, any state of the United States or the District of Columbia; provided, however, that at any time such surviving Person is a limited liability company or limited partnership, there shall be a co-issuer of the notes that is a corporation organized or existing under the laws of the United States, any state of the United States or the District of Columbia;

(2) the Person formed by or surviving any such consolidation or merger (if other than the Company) or the Person to which such sale, assignment, transfer, conveyance, lease or other disposition has been made assumes all the obligations of the Company under the notes, the indenture and any registration rights agreement pursuant to a supplemental indenture or other agreement in a form reasonably satisfactory to the trustee;

(3) immediately after such transaction, no Default or Event of Default exists;

(4) immediately after giving effect to such transaction and any related financing transaction on a pro forma basis as if the same had occurred at the beginning of the applicable four-quarter period, either (i) the Company or the Person formed by or surviving any such consolidation or merger (if other than the Company), or to which such sale, assignment, transfer, conveyance, lease or other disposition has been made, would be permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock or (ii) the Fixed Charge Coverage Ratio of the Company or the Person formed by or surviving any such consolidation or merger (if other than the Company), or to which such sale, assignment, transfer, conveyance, lease or other disposition has been made, is equal to or greater than the Fixed Charge Coverage Ratio of the Company immediately prior to such transaction; and

(5) the Company has delivered to the trustee an officers certificate and an opinion of counsel, each stating that such consolidation, merger or disposition and such supplemental indenture, if any, comply with the indenture.

Notwithstanding the restrictions described in the foregoing clause (4), (i) any Restricted Subsidiary of the Company may consolidate with or merge into the Company and (ii) the Company may consolidate with or merge into or dispose all or substantially all of its properties or assets to any Guarantor; and the Company, in the case of (i) or (ii), will not be required to comply with the preceding clause (4) in connection with any such consolidation, merger or disposition.

Notwithstanding the second preceding paragraph, the Company may reorganize as any other form of entity in accordance with the following procedures *provided* that:

(1) the reorganization involves the conversion (by merger, sale, contribution or exchange of assets or otherwise) of the Company into a form of entity other than a corporation formed under Delaware law;

(2) the entity so formed by or resulting from such reorganization is an entity organized or existing under the laws of the United States, any state thereof or the District of Columbia;

(3) the entity so formed by or resulting from such reorganization assumes all the obligations of the Company under the notes, the indenture and any registration rights agreement pursuant to a supplemental indenture or other agreement in a form reasonably satisfactory to the trustee;

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(4) immediately after such reorganization no Default (other than a Reporting Default) or Event of Default exists; and

(5) such reorganization is not materially adverse to the holders or Beneficial Owners of the notes (for purposes of this clause (5) a reorganization will not be considered materially adverse to the holders or Beneficial Owners of the notes solely because the successor or survivor of such reorganization (a) is subject to federal or state income taxation as an entity or (b) is considered to be an includible corporation of an affiliated group of corporations within the meaning of Section 1504(b) of the Code or any similar state or local law).

For purposes of the foregoing, the transfer (by lease, assignment, sale or otherwise, in a single transaction or series of transactions) of all or substantially all of the properties or assets of one or more Restricted Subsidiaries of the Company, the Capital Stock of which constitutes all or substantially all of the properties or assets of the Company, shall be deemed to be the transfer of all or substantially all of the properties or assets of the Company.

Upon any consolidation or merger or any sale, assignment, transfer, conveyance, lease or other disposition of all or substantially all of the properties or assets of the Company in accordance with the foregoing in which the Company is not the surviving entity, the surviving Person formed by such consolidation or into or with which the Company is merged or to which such sale, assignment, transfer, conveyance, lease or other disposition is made shall succeed to, and be substituted for, and may exercise every right and power of, the Company under the indenture, the notes and any registration rights agreement with the same effect as if such surviving Person had been named as the Company in the indenture, the notes and any registration rights agreement, and thereafter (except in the case of a lease of all or substantially all of the Company s properties or assets), the Company will be relieved of all obligations and covenants under the indenture, the notes and any registration rights agreement.

Although there is a limited body of case law interpreting the phrase substantially all, there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve all or substantially all of the properties or assets of a Person.

Transactions with Affiliates

The Company will not, and will not permit any of its Restricted Subsidiaries to, make any payment to, or sell, lease, transfer or otherwise dispose of any of its properties or assets to, or purchase any property or assets from, or enter into or make or amend any transaction, contract, agreement, understanding, loan, advance or Guarantee with, or for the benefit of, any Affiliate of the Company (each, an ***Affiliate Transaction***) involving aggregate consideration to or from the Company or a Restricted Subsidiary in excess of $5.0 million, unless:

(1) the Affiliate Transaction is on terms that are no less favorable to the Company or the relevant Restricted Subsidiary than those that could have been obtained in a comparable transaction by the Company or such Restricted Subsidiary with an unrelated Person or, if, as determined in good faith by the Company, no comparable transaction is available with which to compare such Affiliate Transaction, such Affiliate Transaction is otherwise fair to the Company or the relevant Restricted Subsidiary from a financial point of view; and

(2) the Company delivers to the trustee:

(a) with respect to any Affiliate Transaction or series of related Affiliate Transactions involving aggregate consideration in excess of $20.0 million, an officers certificate certifying that such Affiliate Transaction or series of related Affiliate Transactions complies with this covenant; and

(b) with respect to any Affiliate Transaction or series of related Affiliate Transactions involving aggregate consideration in excess of $50.0 million, an officers certificate certifying that such Affiliate Transaction or series of related Affiliate Transactions complies with this covenant and that such Affiliate Transaction or series of related Affiliate Transactions has been approved by a majority of the members of the Board of Directors of the Company and by a majority of the disinterested members of the Board of Directors of the Company, if any.

The following items will not be deemed to be Affiliate Transactions and, therefore, will not be subject to the provisions of the prior paragraph:

(1) any employment agreement, employee benefit plan, officer or director indemnification agreement or any similar arrangement entered into by the Company or any of its Restricted Subsidiaries in the ordinary course of business and payments pursuant thereto;

(2) transactions between or among the Company and/or its Restricted Subsidiaries;

(3) transactions with a Person (other than an Unrestricted Subsidiary of the Company) that is an Affiliate of the Company solely because the Company owns, directly or through a Restricted Subsidiary, an Equity Interest in, or controls, such Person;

(4) payment of reasonable and customary fees and reimbursement of expenses (pursuant to indemnity agreements or otherwise) of, or provision of directors and officers liability insurance, compensation, indemnification and other benefits to, officers, directors, employees or consultants of the Company or any of its Subsidiaries;

(5) any issuance of Equity Interests (other than Disqualified Stock) of the Company to Affiliates of the Company;

(6) any Restricted Payments or Permitted Investments or Permitted Payments that are permitted by the provisions of the indenture described above under the caption Certain Covenants Restricted Payments ;

(7) transactions between the Company or any of its Restricted Subsidiaries and any Person that would not otherwise constitute an Affiliate Transaction except for the fact that one director of such other Person is also a director of the Company or such Restricted Subsidiary, as applicable; *provided* that such director abstains from voting as a director of the Company or such Restricted Subsidiary, as applicable, on any matter involving such other Person;

(8) any transaction in which the Company or any of its Restricted Subsidiaries, as the case may be, delivers to the trustee a letter from an accounting, appraisal, advisory or investment banking firm of national standing stating that such transaction is fair to the Company or such Restricted Subsidiary from a financial point of view or that such transaction meets the requirements of clause (1) of the preceding paragraph;

(9) (a) guarantees by the Company or any of its Restricted Subsidiaries of performance of obligations of the Company s Unrestricted Subsidiaries in the ordinary course of business, except for guarantees of Indebtedness in respect of borrowed money, and (b) pledges by the Company or any Restricted Subsidiary of the Company of (or any Guarantee by the Company or any Restricted Subsidiary limited in recourse solely to) Equity Interests in Unrestricted Subsidiaries for the benefit of lenders or other creditors of the Company s Unrestricted Subsidiaries;

(10) transactions with Unrestricted Subsidiaries, customers, clients, suppliers or purchasers or sellers of goods or services, or lessors or lessees of property, in each case in the ordinary course of business and otherwise in compliance with the terms of the indenture which are, in the aggregate (taking into account all the costs and benefits associated with such transactions), not materially less favorable to the Company and its Restricted Subsidiaries than those that would have been obtained in a comparable transaction by the Company or such Restricted Subsidiary with an unrelated person or are on terms at least as favorable as might reasonably have been obtained at such time from an unaffiliated party, in each case, as determined in good faith by the Company;

(11) transactions (other than purchases or sales of assets) effected in accordance with the terms of (a) the Omnibus Agreement and any other agreements that are described in the offering memorandum dated June 25, 2014 and identified in the indenture, in each case as such agreements were in effect on the date of the indenture, (b) any amendment or replacement of any of such agreements or (c) any agreement entered into after the date of the indenture that is similar to any such agreements, so long as, in the case of clause (b) or (c), the terms of any such amendment or replacement agreement or future agreement, taken as a whole, are no less advantageous to the Company or no less favorable to the holders in any material respect than the agreement so amended or replaced or the similar such agreement, respectively, as determined in good faith by the Company;

(12) in the case of contracts for exploring for, producing, marketing, storing or otherwise handling Hydrocarbons, or activities or services reasonably related or ancillary thereto, or other operational contracts, any such contracts entered into in the ordinary course of business and otherwise in compliance with the terms of the indenture which are fair to the Company and its Restricted Subsidiaries, or are on terms at least as favorable as might reasonably have been obtained at such time from an unaffiliated party, in each case, as determined in good faith by the Company; and

(13) loans or advances to employees in the ordinary course of business not to exceed $5.0 million in the aggregate at any one time outstanding.

Additional Note Guarantees

If, after the date of the indenture, any Restricted Subsidiary of the Company that is not already a Guarantor Guarantees or otherwise becomes an obligor with respect to any other Indebtedness of the Company or any Guarantor in excess of the De Minimis Guaranteed Amount, then such Restricted Subsidiary will become a Guarantor by executing a supplemental indenture and delivering it to the trustee within 20 Business Days of the date on which it Guaranteed or became an obligor with respect to such Indebtedness; *provided*, *however*, that the preceding shall not apply to Subsidiaries of the Company that have properly been designated as Unrestricted Subsidiaries in accordance with the indenture for so long as they continue to constitute Unrestricted Subsidiaries. Notwithstanding the preceding, any Note Guarantee of a Restricted Subsidiary that was incurred pursuant to this paragraph shall provide by its terms that it shall be automatically and unconditionally released at such time as such Guarantor ceases to Guarantee or otherwise be an obligor with respect to any other Indebtedness of the Company or any other Guarantor in excess of the De Minimis Guaranteed Amount, *provided* no Event of Default has occurred and is continuing at the time of such release.

Designation of Restricted and Unrestricted Subsidiaries

At the time the notes are originally issued, all of the Subsidiaries of the Company will be Restricted Subsidiaries other than the MLP and its Subsidiaries.

The Board of Directors of the Company may designate any Restricted Subsidiary to be an Unrestricted Subsidiary if that designation would not cause a Default. If a Restricted Subsidiary is designated as an Unrestricted Subsidiary, the aggregate Fair Market Value of all outstanding Investments owned by the Company and its Restricted Subsidiaries in the Subsidiary designated as an Unrestricted Subsidiary will be deemed to either be an Investment made as a Restricted Payment as of the time of the designation that will reduce the amount available for Restricted Payments under the covenant described above under the caption Certain Covenants Restricted Payments or represent a Permitted Investment under one or more clauses of the definition of Permitted Investments, as determined in good faith by the

Company. That designation will only be permitted if the Investment would be permitted at that time and if the Subsidiary so designated otherwise meets the definition of an Unrestricted Subsidiary.

Any designation of a Subsidiary of the Company as an Unrestricted Subsidiary will be evidenced to the trustee by filing with the trustee a certified copy of a resolution of the Board of Directors of the Company giving effect to such designation and an officers certificate certifying that such designation complied with the preceding conditions and was permitted by the covenant described above under the caption Certain Covenants Restricted Payments. If, at any time, any Unrestricted Subsidiary would fail to meet the preceding requirements as an Unrestricted Subsidiary, it will thereafter cease to be an Unrestricted Subsidiary for purposes of the indenture and any Indebtedness of such Subsidiary will be deemed to be incurred by a Restricted Subsidiary of the Company as of such date and, if such Indebtedness is not permitted to be incurred as of such date under the covenant described under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock, the Company will be in default of such covenant.

The Board of Directors of the Company may at any time designate any Unrestricted Subsidiary to be a Restricted Subsidiary of the Company; *provided* that such designation will be deemed to be an incurrence of Indebtedness by a Restricted Subsidiary of the Company of any outstanding Indebtedness of such Unrestricted Subsidiary, and such designation will only be permitted if (1) such Indebtedness is permitted under the covenant described under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock, either as Permitted Debt or pursuant to the first paragraph of such covenant with the Fixed Charge Coverage Ratio calculated on a pro forma basis as if such designation had occurred at the beginning of the applicable reference period; and (2) no Default or Event of Default would be in existence following such designation.

Reports

Whether or not required by the rules and regulations of the SEC, so long as any notes are outstanding, the Company will furnish to the holders of notes or cause the trustee to furnish to the holders of notes (or file with the SEC for public availability), within the time periods specified in the SEC s rules and regulations applicable to a non-accelerated filer, after giving effect to all applicable extensions and cure periods:

(1) all quarterly and annual reports that would be required to be filed with the SEC on Forms 10-Q and 10-K if the Company were required to file such reports, including a Management s Discussion and Analysis of Financial Condition and Results of Operations and, with respect to the annual report only, a report on the Company s consolidated financial statements by the Company s certified independent accountants; and

(2) all current reports that would be required to be filed with the SEC on Form 8-K if the Company were required to file such reports.

The availability of the foregoing reports on the SEC s EDGAR filing system will be deemed to satisfy the foregoing delivery requirements.

All such reports will be prepared in all material respects in accordance with all of the rules and regulations applicable to such reports.

If, notwithstanding the foregoing, the SEC will not accept the Company s filings for any reason, the Company will post the reports referred to in the preceding paragraphs on its website within the time periods applicable to a non-accelerated filer that would apply if the Company were required to file those reports with the SEC.

If the Company has designated any of its Subsidiaries as Unrestricted Subsidiaries (other than Unrestricted Subsidiaries that, when taken together with all other Unrestricted Subsidiaries, are minor within the meaning of Rule 3-10 of Regulation S-X), then the quarterly and annual financial information required by the second preceding paragraph will include, to the extent material, a reasonably detailed presentation, either on the face of the financial statements or in the footnotes thereto, and in Management s Discussion and Analysis of Financial Condition and

Results of Operations, of the financial condition and results of operations of the Company and its Restricted Subsidiaries separate from the financial condition and results of operations of the Unrestricted Subsidiaries of the Company.

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This covenant does not impose any duty on the Company under the Sarbanes Oxley Act of 2002 and the related SEC rules that would not otherwise be applicable.

Any and all Defaults or Events of Default arising from a failure to furnish or file in a timely manner a report or information required by this covenant shall be deemed cured (and the Company shall be deemed to be in compliance with this covenant) upon furnishing or filing such report or information as contemplated by this covenant (but without regard to the date on which such report or information is so furnished or filed); *provided* that such cure shall not otherwise affect the rights of the holders under Events of Defaults and Remedies if the principal, interest and premium, if any, have been accelerated in accordance with the terms of the indenture and such acceleration has not been rescinded or cancelled prior to such cure.

In addition, for so long as the notes remain outstanding, the Company will furnish to the holders and Beneficial Owners of the notes and to securities analysts and prospective investors in the notes, upon their request, the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act.

The Company will be deemed to have furnished to the holders and Beneficial Owners of the notes and to securities analysts and prospective investors the reports referred to in clauses (1) and (2) of the first paragraph of this covenant or the information referred to in the immediately preceding paragraph of this covenant if the Company has posted such reports or information on the Company Website. For purposes of this covenant, the term Company Website means the collection of web pages that may be accessed on the World Wide Web using the URL address http://www.memorialrd.com or such other address as the Company may from time to time designate in writing to the Trustee.

Events of Default and Remedies

Each of the following is an Event of Default :

(1) default for 30 days in the payment when due of interest on the notes;

(2) default in the payment when due (at Stated Maturity, upon redemption or otherwise) of the principal of, or premium, if any, on, the notes;

(3) failure by the Company for 30 days after written notice has been given, by certified mail, (1) to the Company by the trustee or (2) to the Company and the trustee by the holders of at least 25% in aggregate principal amount of the notes then outstanding to comply with the provisions described under the captions (a) Repurchase at the Option of Holders Change of Control or (b) Repurchase at the Option of Holders Asse Sales ;

(4) failure by the Company to comply with the provisions described under the caption Certain Covenants Merger, Consolidation or Sale of Assets ;

(5)

failure by the Company for 120 days after written notice has been given, by certified mail, (1) to the Company by the trustee or (2) to the Company and the trustee by the holders of at least 25% in aggregate principal amount of the notes then outstanding to comply with the provisions described under Certain Covenants Reports ;

(6) failure by the Company for 60 days after written notice has been given, by certified mail, (1) to the Company by the trustee or (2) to the Company and the trustee by the holders of at least 25% in aggregate principal amount of the notes then outstanding to comply with any of the other agreements in the indenture;

(7) default under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any Indebtedness for money borrowed by the Company or any of its Restricted Subsidiaries (or the payment of which is guaranteed by the Company or any of its Restricted Subsidiaries), whether such Indebtedness or Guarantee now exists, or is created after the date of the indenture, if that default:

(a) is caused by a failure to pay principal of, and interest and premium, if any, on, such Indebtedness prior to the expiration of the grace period provided in such Indebtedness on the date of such default (a ***Payment Default***); or

(b) results in the acceleration of such Indebtedness prior to its express maturity,

and, in each case, the principal amount of any such Indebtedness, together with the principal amount of any other such Indebtedness under which there has been a Payment Default or the maturity of which has been so accelerated, aggregates $25.0 million or more; *provided, however*, if, prior to any acceleration of the notes, (i) any such Payment Default is cured or waived, (ii) any such acceleration is rescinded, or (iii) such Indebtedness is repaid during the 60 day period commencing upon the end of any applicable grace period for such Payment Default or the occurrence of such acceleration, as the case may be, any Default or Event of Default (but not any acceleration of the notes) caused by such Payment Default or acceleration shall be automatically rescinded, so long as such rescission does not conflict with any judgment, decree or applicable law;

(8) failure by the Company or any of its Restricted Subsidiaries to pay final judgments entered by a court or courts of competent jurisdiction aggregating in excess of $25.0 million (to the extent not covered by insurance by a reputable and creditworthy insurer as to which the insurer has not disclaimed coverage), which judgments are not paid, discharged or stayed, for a period of 60 days;

(9) except as permitted by the indenture, any Note Guarantee is held in any judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force and effect, or any Guarantor, or any Person acting on behalf of any Guarantor, denies or disaffirms its obligations under its Note Guarantee, except, in each case, by reason of the release of such Note Guarantee in accordance with the indenture; and

(10) certain events of bankruptcy or insolvency described in the indenture with respect to the Company or any of its Restricted Subsidiaries that is a Significant Subsidiary or any group of its Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

In the case of an Event of Default arising from certain events of bankruptcy or insolvency, with respect to the Company, any Restricted Subsidiary of the Company that is a Significant Subsidiary or any group of Restricted Subsidiaries of the Company that, taken together, would constitute a Significant Subsidiary, all outstanding 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 aggregate principal amount of the then outstanding notes may declare all the notes to be due and payable immediately.

Holders of the notes may not enforce the indenture or the notes except as provided in the indenture. Subject to certain limitations, holders of a majority in aggregate principal amount of the then outstanding notes may direct the trustee in its exercise of any trust or power. The trustee may withhold from holders of the notes notice of any continuing Default or Event of Default if it determines that withholding notice is in their interest, except a Default or Event of Default relating to the payment of principal of, or interest or premium, if any, on, the notes.

The holders of a majority in aggregate principal amount of the then outstanding notes by written notice to the trustee may, on behalf of the holders of all of the notes, rescind an acceleration or waive any existing Default or Event of Default and its consequences under the indenture, if the rescission would not conflict with any judgment or decree, except a continuing Default or Event of Default in the payment of principal of, or interest or premium, if any, on, the notes.

The Company is required to deliver to the trustee annually an officers certificate regarding compliance with the indenture. Upon any Officer of the Company becoming aware of any Default or Event of Default, the Company is required to deliver to the trustee a statement specifying such Default or Event of Default within 30 days after such Officer becomes aware of the occurrence and continuance of such Default or Event of Default, unless such Default or Event of Default has been cured before the end of the 30-day period.

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No Personal Liability of Directors, Officers, Employees and Stockholders

No past, present or future director, officer, partner, employee, incorporator, member, manager, stockholder, unitholder or other owner of the Capital Stock of the Company or any Guarantor, as such, will have any liability for any obligations of the Company or the Guarantors under the notes, the indenture or the Note Guarantees or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder of notes by accepting a note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the notes. The waiver may not be effective to waive liabilities under the federal securities laws.

Legal Defeasance and Covenant Defeasance

The Company may at any time, at the option of its Board of Directors evidenced by a resolution set forth in an officers certificate, elect to have all of its obligations discharged with respect to the outstanding notes and all obligations of the Guarantors discharged with respect to their Note Guarantees (***Legal Defeasance***) except for:

(1) the rights of holders of outstanding notes to receive payments in respect of the principal of, or interest or premium, if any, on, such notes when such payments are due from the trust referred to below;

(2) the Company s obligations with respect to the notes concerning issuing temporary notes, registration of notes, mutilated, destroyed, lost or stolen notes and the maintenance of an office or agency for payment and money for security payments held in trust;

(3) the rights, powers, trusts, duties and immunities of the trustee under the indenture, and the Company s and the Guarantors obligations in connection therewith; and

(4) the Legal Defeasance provisions of the indenture.

In addition, the Company may, at its option and at any time, elect to have its obligations and the obligations of the Guarantors released with respect to (x) all of the covenants that are described under Certain Covenants and under Repurchase at the Option of Holders (other than the covenant described in the first paragraph under Certain Covenants Merger, Consolidation or Sale of Assets, except to the extent described below), including the Company s obligation to make Change of Control Offers and Asset Sale Offers, and (y) the limitations described in clause (4) of the first paragraph under Certain Covenants Merger, Consolidation or Sale of Assets (***Covenant Defeasance***) and thereafter any omission to comply with those covenants or limitations will not constitute a Default or Event of Default with respect to the notes. In the event Covenant Defeasance occurs, all Events of Default described under Events of Default and Remedies (except those relating to payments on the notes or bankruptcy or insolvency events as to the Company) will no longer constitute an Event of Default with respect to the notes.

In order to exercise either Legal Defeasance or Covenant Defeasance:

(1) the Company must irrevocably deposit with the trustee, in trust, for the benefit of the holders of the notes, cash in U.S. dollars, non-callable Government Securities, or a combination thereof, in

amounts as will be sufficient, in the opinion of a nationally recognized investment bank, appraisal firm or firm of independent public accountants, to pay the principal of, and interest and premium, if any, on, the outstanding notes on the stated date for payment thereof or on the applicable redemption date, as the case may be, and the Company must specify whether the notes are being defeased to such stated date for payment or to a particular redemption date;

(2) in the case of Legal Defeasance, the Company must deliver to the trustee an opinion of counsel reasonably acceptable to the trustee confirming that

(a) the Company has received from, or there has been published by, the Internal Revenue Service a ruling or

(b) since the date of the indenture, there has been a change in the applicable federal income tax law, in either case to the effect that, and based thereon such opinion of counsel will confirm that, the holders of the outstanding notes will not recognize income, gain or loss for federal income tax purposes as a result of such Legal Defeasance and will be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Legal Defeasance had not occurred;

(3) in the case of Covenant Defeasance, the Company must deliver to the trustee an opinion of counsel reasonably acceptable to the trustee confirming that the holders of the outstanding notes will not recognize income, gain or loss for federal income tax purposes as a result of such Covenant Defeasance and will be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Covenant Defeasance had not occurred;

(4) the Company must deliver to the trustee an officer s certificate stating that no Default or Event of Default has occurred and is continuing on the date of such deposit (other than a Default or Event of Default resulting from the borrowing of funds to be applied to such deposit (and any similar concurrent deposit relating to other Indebtedness), and the granting of Liens to secure such borrowings, all or a portion of which are to be applied to such deposit);

(5) the Company must deliver to the trustee an officer s certificate stating that such Legal Defeasance or Covenant Defeasance will not result in a breach or violation of, or constitute a default under, any material agreement or instrument (other than the indenture and the agreements governing any other Indebtedness being defeased, discharged or replaced) to which the Company or any Guarantor is a party or by which the Company or any Guarantor is bound;

(6) the Company must deliver to the trustee an officers certificate stating that the deposit was not made by the Company with the intent of preferring the holders of notes over the other creditors of the Company with the intent of defeating, hindering, delaying or defrauding any creditors of the Company or others; and

(7) the Company must deliver to the trustee an officers certificate and an opinion of counsel, each stating that all conditions precedent relating to the Legal Defeasance or the Covenant Defeasance, as the case may be, have been complied with.

Amendment, Supplement and Waiver

Except as provided in the next two succeeding paragraphs, the indenture, the notes or the Note Guarantees may be amended or supplemented with the consent of the holders of a majority in aggregate principal amount of the then outstanding notes (including, without limitation, additional notes, if any) voting as a single class (including, without limitation, consents obtained in connection with a tender offer or exchange offer for, or purchase of, the notes), and any existing Default or Event of Default (other than a Default or Event of Default in the payment of the principal of, or interest or premium, if any, on, the notes, except a payment default resulting from an acceleration that has been rescinded) or compliance with any provision of the indenture, the notes or the Note Guarantees may be waived with the consent of the holders of a majority in aggregate principal amount of the then outstanding notes (including, without limitation, additional notes, if any) voting as a single class (including, without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, notes).

Without the consent of each holder of notes affected, an amendment, supplement or waiver may not (with respect to any notes held by a non-consenting holder):

(1) reduce the principal amount of notes whose holders must consent to an amendment, supplement or waiver;

(2) reduce the principal of or change the fixed maturity of any note or alter or waive any of the provisions with respect to the redemption of the notes (except those provisions relating to the covenants described above under the caption Repurchase at the Option of Holders);

(3) reduce the rate of or change the time for payment of interest, including default interest, on any note;

(4) waive a Default or Event of Default in the payment of principal of, or interest or premium, if any, on, the notes (except (i) a payment required by one of the covenants described above under the caption Repurchase at the Option of Holders or (ii) a rescission of acceleration of the notes by the holders of a majority in aggregate principal amount of the then outstanding notes and a waiver of the payment default that resulted from such acceleration);

(5) make any note payable in money other than that stated in the notes;

(6) make any change in the provisions of the indenture relating to waivers of past Defaults or the rights of holders of notes to receive payments of principal of, or interest or premium, if any, on, the notes (other than a payment required by one of the covenants described above under the caption Repurchase at the Option of Holders);

(7) waive a redemption payment with respect to any note (other than a payment required by one of the covenants described above under the caption Repurchase at the Option of Holders);

(8) release any Guarantor from any of its obligations under its Note Guarantee or the indenture, except in accordance with the terms of the indenture; or

(9) make any change in the preceding amendment, supplement and waiver provisions.

Notwithstanding the preceding, without the consent of any holder of notes, the Company, the Guarantors and the trustee may amend or supplement the indenture, the notes or the Note Guarantees:

(1) to cure any ambiguity, defect or inconsistency;

(2) to provide for uncertificated notes in addition to or in place of certificated notes;

(3) to provide for the assumption of the Company s or a Guarantor s obligations to holders of notes and Note Guarantees in the case of a merger or consolidation or sale of all or substantially all of the Company s or such Guarantor s properties or assets, as applicable;

(4) to make any change that would provide any additional rights or benefits to the holders of notes or that does not adversely affect the legal rights under the indenture of any holder;

(5) to comply with requirements of the SEC in order to effect or maintain the qualification of the indenture under the Trust Indenture Act;

(6) to conform the text of the indenture, the notes or the Note Guarantees to any provision of the Description of Notes section of the Company s offering memorandum dated June 25, 2014;

(7) to provide for the issuance of additional notes in accordance with the limitations set forth in the indenture as of the date of the indenture;

(8) to secure the notes or the Note Guarantees pursuant to the requirements of the covenant described above under the subheading Certain Covenants Liens ;

(9) to add any additional Guarantor or to evidence the release of any Guarantor from its Note Guarantee, in each case as provided in the indenture;

(10) to evidence or provide for the acceptance of appointment under the indenture of a successor trustee; or

(11) to provide for the reorganization of the Company as any other form of entity in accordance with the third paragraph of Certain Covenants Merger, Consolidation or Sale of Assets.

The consent of the holders is not necessary under the indenture to approve the particular form of any proposed amendment, supplement or waiver. It is sufficient if such consent approves the substance of the proposed amendment, supplement or waiver. After an amendment, supplement or waiver under the indenture requiring the approval of the holders becomes effective, the Company will mail to the holders a notice briefly describing the amendment, supplement or waiver. However, the failure to give such notice, or any defect in the notice, will not impair or affect the validity of the amendment, supplement or waiver.

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Satisfaction and Discharge

The indenture will be discharged and will cease to be of further effect as to all notes issued thereunder (except as to surviving rights of registration of transfer or exchange of the notes and as otherwise specified in the indenture), when:

(1) either:

(a) all notes that have been authenticated, except lost, stolen or destroyed notes that have been replaced or paid and notes for whose payment money has been deposited in trust and thereafter repaid to the Company, have been delivered to the trustee for cancellation; or

(b) all notes that have not been delivered to the trustee for cancellation have become due and payable or will become due and payable within one year by reason of the mailing of a notice of redemption or otherwise and either the Company or any Guarantor has irrevocably deposited or caused to be deposited with the trustee as trust funds in trust solely for the benefit of the holders, cash in U.S. dollars, non-callable Government Securities, or a combination thereof, in such amounts as will be sufficient, without consideration of any reinvestment of interest, to pay and discharge the entire Indebtedness on the notes not delivered to the trustee for cancellation for principal of, or interest or premium, if any, on, the notes to the date of Stated Maturity or redemption;

(2) in respect of clause (1)(b), no Event of Default has occurred and is continuing on the date of the deposit (other than an Event of Default resulting from the borrowing of funds to be applied to such deposit and any similar deposit relating to other Indebtedness and, in each case, the granting of Liens to secure such borrowings, all or a portion of which are to be applied to such deposit) and the deposit will not result in a breach or violation of, or constitute a default under, any other instrument to which the Company or any Guarantor is a party or by which the Company or any Guarantor is bound (other than with respect to the borrowing of funds to be applied to such deposit and any similar deposit relating to other Indebtedness, and in each case the granting of Liens to secure such borrowings, all or a portion of which are to be applied to such deposit);

(3) the Company has paid or caused to be paid all other sums payable by the Company under the indenture; and

(4) the Company has delivered irrevocable instructions to the trustee to apply the deposited money toward the payment of the notes at Stated Maturity or on the redemption date, as the case may be.

In addition, the Company must deliver an officers certificate and an opinion of counsel to the trustee stating that all conditions precedent to satisfaction and discharge have been satisfied.

Concerning the Trustee

U.S. Bank National Association is the trustee under the indenture.

If the trustee becomes a creditor of the Company or any Guarantor, the indenture will limit the right of the trustee to obtain payment of claims in certain cases, or to realize on certain property received in respect of any such claim as security or otherwise. The trustee is permitted to engage in other transactions; however, if it acquires any conflicting interest (as defined in the Trust Indenture Act) after a Default has occurred and is continuing it must eliminate such conflict within 90 days, apply to the SEC for permission to continue as trustee (if the indenture has been qualified under the Trust Indenture Act) or resign.

The holders of a majority in aggregate principal amount of the then outstanding notes have the right to direct the time, method and place of conducting any proceeding for exercising any remedy available to the trustee, subject to certain exceptions. In case an Event of Default has occurred and is continuing, the trustee will be required, in the exercise of its powers, to use the degree of care of a prudent man in the conduct of his own affairs. Subject to such provisions, the trustee will be under no obligation to exercise any of its rights or powers under the indenture at the request of any holder of notes, unless such holder has offered to the trustee reasonable indemnity or security satisfactory to it against any loss, liability or expense.

Governing Law

The indenture, the old notes and the Note Guarantees are, and the new notes and the New Note Guarantees will be, governed by, and construed in accordance with, the laws of the State of New York.

Book-Entry, Delivery and Form

The new notes will be issued initially only in the form of one or more global notes (collectively, the ***Global Notes***). The Global Notes will be deposited upon issuance with the trustee as custodian for DTC and registered in the name of DTC s nominee, Cede & Co., in each case for credit to an account of a direct or indirect participant in DTC as described below. Beneficial interests in the Global Notes may be held through the Euroclear System (***Euroclear***) and Clearstream Banking, S.A. (***Clearstream***) (as indirect participants in DTC). The Global Notes may be transferred, in whole but not in part, only to another nominee of DTC or to a successor of DTC or its nominee. Beneficial interests in the Global Notes may not be exchanged for notes in registered, certificated form (***Certificated Notes***) except in the limited circumstances described below. See Exchange of Global Notes for Certificated Notes.

In addition, transfers of beneficial interests in the Global Notes will be subject to the applicable rules and procedures of DTC and its direct or indirect participants (including, if applicable, those of Euroclear and Clearstream), which may change from time to time.

Depository Procedures

The following description of the operations and procedures of DTC, Euroclear and Clearstream are provided solely as a matter of convenience. These operations and procedures are solely within the control of the respective settlement systems and are subject to changes by them. The Company takes no responsibility for these operations and procedures and urges investors to contact the system or their participants directly to discuss these matters.

DTC has advised the Company that DTC is a limited-purpose trust company created to hold securities for its participating organizations (collectively, the ***Participants***) and to facilitate the clearance and settlement of transactions in those securities between Participants through electronic book-entry changes in accounts of its Participants. The Participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. Access to DTC s system is also available to other entities such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Participant, either directly or indirectly (collectively, the ***Indirect Participants***). Persons who are not Participants may beneficially own securities held by or on behalf of DTC only through the Participants or the Indirect Participants. The ownership interests in, and transfers of ownership interests in, each security held by or on behalf of DTC are recorded on the records of the Participants and Indirect Participants.

DTC has also advised the Company that, pursuant to procedures established by it:

(1)

upon deposit of the Global Notes, DTC will credit the accounts of the Participants designated by the exchange agent with portions of the principal amount of the Global Notes; and

(2) ownership of these interests in the Global Notes will be shown on, and the transfer of ownership of these interests will be effected only through, records maintained by DTC (with respect to the Participants) or by the Participants and the Indirect Participants (with respect to other owners of beneficial interests in the Global Notes).

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Investors in the Global Notes who are Participants in DTC s system may hold their interests therein directly through DTC. Investors in the Global Notes who are not Participants may hold their interests therein indirectly through organizations (including Euroclear and Clearstream) which are Participants in such system. Euroclear and Clearstream may hold interests in the Global Notes on behalf of their participants through customers securities accounts in their respective names on the books of their depositories, which are Euroclear Bank S.A./ N.V, as operator of Euroclear, and Citibank, N.A., as operator of Clearstream. All interests in a Global Note, including those held through Euroclear or Clearstream, may be subject to the procedures and requirements of DTC. Those interests held through Euroclear or Clearstream may also be subject to the procedures and requirements of such systems.

The laws of some jurisdictions may require that certain Persons take physical delivery in definitive form of securities that they own. Consequently, the ability to transfer beneficial interests in a Global Note to such Persons will be limited to that extent. Because DTC can act only on behalf of Participants, which in turn act on behalf of the Indirect Participants, the ability of a Person having beneficial interests in a Global Note to pledge such interests to Persons that do not participate in the DTC system, or otherwise take actions in respect of such interests, may be affected by the lack of a physical certificate evidencing such interests.

Except as described below, owners of beneficial interests in the Global Notes will not have notes registered in their names, will not receive physical delivery of Certificated Notes and will not be considered the registered owners or holders thereof under the indenture for any purpose.

Payments in respect of the principal of, and interest and premium, if any, on, a Global Note registered in the name of DTC or its nominee will be payable to DTC in its capacity as the registered holder under the indenture. Under the terms of the indenture, the Company, the Guarantors and the trustee will treat the Persons in whose names the notes, including the Global Notes, are registered as the owners of the notes for the purpose of receiving payments and for all other purposes. Consequently, neither the Company, the Guarantors, the trustee nor any agent of the Company, the Guarantors or the trustee has or will have any responsibility or liability for:

(1) any aspect of DTC s records or any Participant s or Indirect Participant s records relating to or payments made on account of beneficial ownership interests in the Global Notes or for maintaining, supervising or reviewing any of DTC s records or any Participant s or Indirect Participant s records relating to the beneficial ownership interests in the Global Notes; or

(2) any other matter relating to the actions and practices of DTC or any of its Participants or Indirect Participants.

DTC has advised the Company that its current practice, at the due date of any payment in respect of securities such as the notes, is to credit the accounts of the relevant Participants with the payment on the payment date unless DTC has reason to believe that it will not receive payment on such payment date. Each relevant Participant is credited with an amount proportionate to its beneficial ownership of an interest in the principal amount of the relevant security as shown on the records of DTC. Payments by the Participants and the Indirect Participants to the beneficial owners of notes will be governed by standing instructions and customary practices and will be the responsibility of the Participants or the Indirect Participants and will not be the responsibility of DTC, the trustee, the Company or the Guarantors. Neither the Company, the Guarantors nor the trustee will be liable for any delay by DTC, its nominee or any Participant or Indirect Participant in identifying the beneficial owners of the notes, and the Company, the Guarantors and the trustee may conclusively rely on and will be protected in relying on instructions from DTC or its nominee for all purposes.

Transfers between the Participants will be effected in accordance with DTC s procedures, and will be settled in same-day funds, and transfers between participants in Euroclear and Clearstream will be effected in accordance with their respective rules and operating procedures.

Cross-market transfers between the Participants, on the one hand, and Euroclear or Clearstream participants, on the other hand, will be effected through DTC in accordance with DTC s rules on behalf of Euroclear or

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Clearstream, as the case may be, by their respective depositaries; however, such cross-market transactions will require delivery of instructions to Euroclear or Clearstream, as the case may be, by the counterparty in such system in accordance with the rules and procedures and within the established deadlines (Brussels time) of such system. Euroclear or Clearstream, as the case may be, will, if the transaction meets its settlement requirements, deliver instructions to its depositary to take action to effect final settlement on its behalf by delivering or receiving interests in the relevant Global Note in DTC, and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Euroclear participants and Clearstream participants may not deliver instructions directly to the depositaries for Euroclear or Clearstream.

DTC has advised the Company that it will take any action permitted to be taken by a holder of notes only at the direction of one or more Participants to whose account DTC has credited the interests in the Global Notes and only in respect of such portion of the aggregate principal amount of the notes as to which such Participant or Participants has or have given such direction. However, if there is an Event of Default under the notes, DTC reserves the right to exchange the Global Notes for Certificated Notes, and to distribute such notes to its Participants.

Although DTC, Euroclear and Clearstream have agreed to the foregoing procedures to facilitate transfers of interests in the Global Notes among participants in DTC, Euroclear and Clearstream, they are under no obligation to perform or to continue to perform such procedures, and may discontinue such procedures at any time. None of the Company, the Guarantors, the trustee or any of their respective agents will have any responsibility for the performance by DTC, Euroclear or Clearstream or their respective participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

Exchange of Global Notes for Certificated Notes

A Global Note is exchangeable for Certificated Notes in minimum denominations of $2,000 and in integral multiples of $1,000 in excess of $2,000, if:

(1) DTC (a) notifies the Company that it is unwilling or unable to continue as depositary for the Global Note or (b) has ceased to be a clearing agency registered under the Exchange Act and, in either event, the Company fails to appoint a successor depositary within 90 days;

(2) the Company, at its option but subject to DTC s requirements, notifies the trustee in writing that they elect to cause the issuance of the Certificated Notes; or

(3) there has occurred and is continuing an Event of Default, and DTC notifies the trustee of its decision to exchange such Global Note for Certificated Notes.

In addition, beneficial interests in a Global Note may be exchanged for Certificated Notes upon prior written notice given to the trustee by or on behalf of DTC in accordance with the indenture. In all cases, Certificated Notes delivered in exchange for any Global Note or beneficial interests in Global Notes will be registered in the names, and issued in any approved denominations, requested by or on behalf of DTC (in accordance with its customary procedures).

Neither the Company, the Guarantors nor the trustee will be liable for any delay by DTC, its nominee or any Participant or Indirect Participant in identifying the beneficial owners of interests in Global Notes, and the Company, the Guarantors and the trustee may conclusively rely on, and will be protected in relying on, instructions from DTC or its nominee for all purposes, including, without limitation, with respect to the registration and delivery, and the respective principal amounts, of the Certificated Notes to be issued.

Exchange of Certificated Notes for Global Notes

Certificated Notes may not be exchanged for beneficial interests in any Global Note, except in the limited circumstances provided in the indenture.

Same-Day Settlement and Payment

The Company will make payments in respect of the notes represented by the Global Notes (including principal, interest and premium, if any) by wire transfer of immediately available funds to the accounts specified by DTC or its nominee. The Company will make all payments of principal, interest and premium, if any, with respect to Certificated Notes in the manner described above under Methods of Receiving Payments on the Notes. The notes represented by the Global Notes are eligible to trade in DTC s Same-Day Funds Settlement System, and any permitted secondary market trading activity in such notes will, therefore, be required by DTC to be settled in immediately available funds. The Company expects that secondary trading in any Certificated Notes will also be settled in immediately available funds.

Because of time zone differences, the securities account of a Euroclear or Clearstream participant purchasing an interest in a Global Note from a Participant will be credited, and any such crediting will be reported to the relevant Euroclear or Clearstream participant, during the securities settlement processing day (which must be a business day for Euroclear and Clearstream) immediately following the settlement date of DTC. DTC has advised the Company that cash received in Euroclear or Clearstream as a result of sales of interests in a Global Note by or through a Euroclear or Clearstream participant to a Participant will be received with value on the settlement date of DTC but will be available in the relevant Euroclear or Clearstream cash account only as of the business day for Euroclear or Clearstream following DTC s settlement date.

Certain Definitions

Set forth below are certain defined terms used in the indenture. Reference is made to the indenture for a full disclosure of all defined terms used therein, as well as any other capitalized terms used herein for which no definition is provided.

Acquired Debt means, with respect to any specified Person:

(1) Indebtedness of any other Person existing at the time such other Person is merged with or into or became a Subsidiary of such specified Person, whether or not such Indebtedness is incurred in connection with, or in contemplation of, such other Person merging with or into, or becoming a Restricted Subsidiary of, such specified Person; and

(2) Indebtedness secured by a Lien encumbering any asset acquired by such specified Person.

Additional Assets means:

(1) any assets used or useful in the Oil and Gas Business, other than Indebtedness or Capital Stock;

(2) the Capital Stock of a Person that becomes a Restricted Subsidiary as a result of the acquisition of such Capital Stock by the Company or any of its Restricted Subsidiaries; or

(3) Capital Stock constituting a minority interest in any Person that at such time is a Restricted Subsidiary; *provided, however*, that any such Restricted Subsidiary described in clause (2) or (3) is primarily engaged in the Oil and Gas Business.

Adjusted Consolidated Net Tangible Assets means (without duplication), as of the date of determination,

(1) the sum of:

(a) the discounted future net revenues from proved oil and natural gas reserves of the Company and its Restricted Subsidiaries calculated in accordance with SEC guidelines before any state or federal income taxes, as estimated in a reserve report prepared as of the end of the Company s most recently completed fiscal year, as increased by, as of the date of determination, the estimated discounted future net revenues from:

(i) estimated proved oil and natural gas reserves of the Company and its Restricted Subsidiaries acquired since the date of such year-end reserve report, and

(ii) estimated proved oil and natural gas reserves of the Company and its Restricted Subsidiaries attributable to extensions, discoveries and other additions and upward revisions of estimates of proved oil and natural gas reserves (including previously estimated development costs incurred during the period and the accretion of discount since the prior period end) since the date of such year-end reserve report due to exploration, development or exploitation, production or other activities which would, in accordance with standard industry practice, cause such revisions,

and decreased by, as of the date of determination, the estimated discounted future net revenue attributable to:

(iii) estimated proved oil and natural gas reserves of the Company and its Restricted Subsidiaries reflected in such reserve report produced or disposed of since the date of such year-end reserve report, and

(iv) reductions in estimated proved oil and natural gas reserves of the Company and its Restricted Subsidiaries reflected in such reserve report attributable to downward revisions of estimates of proved oil and natural gas reserves since such year-end due to changes in geological conditions or other factors which would, in accordance with standard industry practice, cause such revisions;

in the case of the preceding clauses (i) through (iv), calculated on a pre-tax basis in accordance with SEC guidelines (utilizing the prices utilized in the Company s year-end reserve report) and estimated by the Company s petroleum engineers or, at the Company s election, any independent petroleum engineers engaged by the Company for that purpose;

(b) the capitalized costs that are attributable to oil and natural gas properties of the Company and its Restricted Subsidiaries to which no proved oil and natural gas reserves are attributable, based on the Company s books and records as of a date no earlier than the last day of the Company s most recent quarterly or annual period for which internal financial statements are available;

(c) the Consolidated Net Working Capital of the Company and its Restricted Subsidiaries as of a date no earlier than the last day of the Company s most recent quarterly or annual period for which internal financial statements are available; and

(d) the greater of:

(i) the net book value and

(ii)

the appraised value, as estimated by independent appraisers, of other tangible assets (including Investments in unconsolidated Subsidiaries),

in each case, of the Company and its Restricted Subsidiaries as of a date no earlier than the last day of the date of the Company s most recent quarterly or annual period for which internal financial statements are available; *provided* that if no such appraisal has been performed, the Company shall not be required to obtain such an appraisal and only clause (d)(i) of this definition shall apply,

minus, to the extent not otherwise taken into account in the immediately preceding clause (1),

(2) the sum of

(a) minority interests,

(b) any net natural gas balancing liabilities of the Company and its Restricted Subsidiaries as of the last day of the Company s most recent annual or quarterly period for which internal financial statements are available to the extent not deducted in calculating Consolidated Net Working Capital of the Company and its Restricted Subsidiaries in accordance with clause (1)(c) of this definition;

(c) to the extent included in clause (1)(a) above, the discounted future net revenues, calculated in accordance with SEC guidelines (utilizing the prices utilized in the Company s year-end reserve report), attributable to reserves that are required to be delivered to third parties to fully satisfy the obligations of the Company and its Restricted Subsidiaries with respect to Volumetric Production Payments on the schedules specified with respect thereto, and

(d) the discounted future net revenues, calculated in accordance with SEC guidelines, attributable to reserves subject to Dollar-Denominated Production Payments that, based on the estimates of production and price assumptions included in determining the discounted future net revenues specified in clause (1)(a) above, would be necessary to fully satisfy the payment obligations of the Company and its Restricted Subsidiaries with respect to Dollar-Denominated Production Payments on the schedules specified with respect thereto.

If the Company changes its method of accounting from the successful efforts method to the full cost method or a similar method of accounting, Adjusted Consolidated Net Tangible Assets will continue to be calculated as if the Company were still using the successful efforts method of accounting.

Affiliate of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For purposes of this definition, control, as used with respect to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such Person, whether through the ownership of voting securities, by agreement or otherwise. For purposes of this definition, the terms controlling, controlled by and under common control with have correlative meanings.

Applicable Premium means, with respect to any note on any redemption date, the greater of:

(1) 1.0% of the principal amount of the note; or

(2) the excess of:

(a) the present value at such redemption date of (i) the redemption price of the note at July 1, 2017 (such redemption price being set forth in the table appearing above under the caption Optional Redemption) plus (ii) all required interest payments due on the note through July 1, 2017 (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months), over

(b) the principal amount of the note.

as determined in good faith by the Company means a determination made in good faith by the Board of Directors of the Company or any Officer of the Company involved in or otherwise familiar with the transaction for which such determination is being made, any such determination being conclusive for all purposes under the indenture.

Asset Sale means:

(1) the sale, lease (other than operating leases entered into in the ordinary course of business), conveyance or other disposition of any assets or rights by the Company or any of the Company s Restricted Subsidiaries; and

(2) the issuance of Equity Interests by any of the Company s Restricted Subsidiaries or the sale by the Company or any of the Company s Restricted Subsidiaries of Equity Interests in any of the Company s Subsidiaries (in either case other than Preferred Stock of any Restricted Subsidiary issued in

compliance with the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock, and directors qualifying shares or shares required by applicable law to be held by a Person other than the Company or a Restricted Subsidiary);

provided that, in the case of (1) or (2), the sale, assignment, transfer, conveyance, lease or other disposition of all or substantially all of the properties or assets of the Company and its Subsidiaries (including by way of a merger or consolidation) will be governed by the provisions of the indenture described above under the caption Repurchase at the Option of Holders Change of Control and/or the provisions described above under the caption Certain Covenants Merger, Consolidation or Sale of Assets and not by the provisions of the Asset Sales covenant.

Notwithstanding the preceding, none of the following items will be deemed to be an Asset Sale:

(1) any single transaction or series of related transactions that involves assets or Equity Interests having a Fair Market Value of less than $20.0 million;

(2) a transfer of assets between or among the Company and its Restricted Subsidiaries;

(3) an issuance or sale of Equity Interests by a Restricted Subsidiary of the Company to the Company or to a Restricted Subsidiary of the Company;

(4) the sale, lease or other disposition of products, services, inventory or accounts receivable in the ordinary course of business and any sale or other disposition of surplus, damaged, worn-out or obsolete assets (including the abandonment or other disposition of intellectual property that is, in the reasonable judgment of the Company, no longer economically practicable to maintain or useful in the conduct of the business of the Company and its Restricted Subsidiaries taken as whole);

(5) the abandonment, farm-out, lease or sublease of developed or undeveloped oil or natural gas properties, or the forfeiture of such properties, owned or held by the Company or any of its Restricted Subsidiaries in the ordinary course of business;

(6) licenses and sublicenses by the Company or any of its Restricted Subsidiaries of software, intellectual property or other general intangibles in the ordinary course of business;

(7) any surrender or waiver of contract rights or settlement, release, recovery on or surrender of contract, tort or other claims;

(8) the granting, creation or incurrence of Liens not prohibited by the covenant described above under the caption Certain Covenants Liens and dispositions in connection with Permitted Liens and the exercise by any Person in whose favor a Permitted Lien is granted of any of its rights in respect of such Permitted Lien;

(9) the sale or other disposition of cash or Cash Equivalents or other financial instruments (other than Oil and Gas Hedging Contracts);

(10) a disposition of assets that constitutes (or results in by virtue of the consideration received for such disposition) either a Restricted Payment that does not violate the covenant described above under the caption Certain Covenants Restricted Payments or a Permitted Investment or a Permitted Payment;

(11) a sale or other disposition of Hydrocarbons or other mineral products in the ordinary course of business;

(12) an Asset Swap;

(13) dispositions of crude oil and natural gas properties (whether or not in the ordinary course of business); *provided* that at the time of any such disposition such properties do not have associated with them any proved reserves;

(14) any Production Payments and Reserve Sales; *provided* that any such Production Payments and Reserve Sales, other than incentive compensation programs on terms that are customary in the Oil and Gas Business for geologists, geophysicists and other providers of technical services to the Company or a Restricted Subsidiary, shall have been created, incurred, issued, assumed or Guaranteed in connection with the financing of, and within 60 days after the acquisition of, the property that is subject thereto;

(15) the disposition of assets or Equity Interests received in settlement of debts owing to a Person as a result of foreclosure, perfection or enforcement of any Lien or debt, which debts were owing to such Person; and

(16) any sale of Equity Interests in, or Indebtedness or other securities of, an Unrestricted Subsidiary (other than the MLP).

Asset Swap means any substantially contemporaneous (and in any event occurring within 180 days of each other) purchase and sale or exchange of any assets or properties used or useful in the Oil and Gas Business between the Company or any of its Restricted Subsidiaries and another Person; *provided*, that the Fair Market Value of the properties or assets traded or exchanged by the Company or such Restricted Subsidiary (together with any cash or Cash Equivalents) is reasonably equivalent to the Fair Market Value of the properties or assets (together with any cash or Cash Equivalents) to be received by the Company or such Restricted Subsidiary, and *provided further*, that any net cash or Cash Equivalents received must be applied in accordance with the provisions described above under the caption Repurchase at the Option of Holders Asset Sales if then in effect as if the Asset Swap were an Asset Sale.

Attributable Debt in respect of a sale and leaseback transaction means, at the time of determination, the present value of the obligation of the lessee for net rental payments during the remaining term of the lease included in such sale and leaseback transaction including any period for which such lease has been extended or may, at the option of the lessor, be extended. Such present value shall be calculated using a discount rate equal to the rate of interest implicit in such transaction, determined in accordance with GAAP; *provided, however*, that if such sale and leaseback transaction results in a Capital Lease Obligation, the amount of Indebtedness represented thereby will be determined in accordance with the definition of Capital Lease Obligation.

Beneficial Owner has the meaning assigned to such term in Rule 13d-3 and Rule 13d-5 under the Exchange Act, except that in calculating the beneficial ownership of any particular person (as that term is used in Section 13(d)(3) of the Exchange Act), such person will be deemed to have beneficial ownership of all securities that such person has the right to acquire within one year by conversion or exercise of other securities, whether such right is currently exercisable or is exercisable only after the passage of time. The terms Beneficially Owns and Beneficially Owned have a corresponding meaning. For purposes of this definition, a Person shall be deemed not to Beneficially Own securities that are the subject of a stock purchase agreement, merger agreement, amalgamation agreement, arrangement agreement or similar agreement until consummation of the transactions or, as applicable, series of related transactions contemplated thereby.

Board of Directors means:

(1) with respect to a corporation, the board of directors of the corporation or any committee thereof duly authorized to act on behalf of such board;

(2) with respect to a limited partnership, the board of directors of the general partner of the partnership;

(3) with respect to a limited liability company, the managing member or members or any controlling committee of managing members thereof; and

(4) with respect to any other Person, the board or committee of such Person serving a similar function.

Business Day means any day other than a Legal Holiday.

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Capital Lease Obligation means, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet prepared in accordance with GAAP, with the amount of Indebtedness represented by such obligation being the capitalized amount of such obligation determined in accordance with GAAP, and the Stated Maturity thereof being the date of the last payment of rent or any other amount due under such lease prior to the first date upon which such lease may be prepaid by the lessee without payment of a penalty. Notwithstanding the foregoing, any lease (whether entered into before or after the date of the indenture) that would have been classified as an operating lease pursuant to GAAP as in effect on the date of the indenture will be deemed not to represent a Capital Lease Obligation. For purposes of the covenant described above under the caption Certain Covenants Liens, a Capital Lease Obligation will be deemed to be secured by a Lien on the property being leased.

Capital Stock means:

(1) in the case of a corporation, corporate stock;

(2) in the case of an association or business entity, any and all shares, interests, participations, rights or other equivalents (however designated) of corporate stock;

(3) in the case of a partnership or limited liability company, partnership interests (whether general or limited) or membership interests; and

(4) any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distributions of assets of, the issuing Person,

but excluding from all of the foregoing any debt securities exercisable for, exchangeable for or convertible into Capital Stock, whether or not such debt securities include any right of participation with Capital Stock.

Cash Equivalents means:

(1) United States dollars;

(2) securities issued or directly and fully guaranteed or insured by the United States government or any agency or instrumentality of the United States government (*provided* that the full faith and credit of the United States is pledged in support of those securities) having maturities of not more than one year from the date of acquisition;

(3) marketable general obligations issued by any state of the United States of America or any political subdivision of any such state or any public instrumentality thereof maturing within one year from the date of acquisition thereof and, at the time of acquisition thereof, having a credit rating of A or better from either S&P or Moody s;

(4) certificates of deposit, demand deposits and eurodollar time deposits with maturities of one year or less from the date of acquisition, bankers acceptances with maturities not exceeding six months and overnight bank deposits, in each case, with any domestic commercial bank having capital and surplus in excess of $500.0 million or that is a lender under the Credit Agreement;

(5) repurchase obligations with a term of not more than seven days for underlying securities of the types described in clauses (2), (3) and (4) above entered into with any financial institution meeting the qualifications specified in clause (4) above;

(6) commercial paper having one of the two highest ratings obtainable from Moody s or S&P and, in each case, maturing within one year after the date of acquisition;

(7) money market funds at least 95% of the assets of which constitute Cash Equivalents of the kinds described in clauses (1) through (6) of this definition;

(8) with respect to any Foreign Subsidiary of the Company, investments denominated in local currency that are similar to the items specified in clauses (1) through (7) above; and

(9) marketable short-term money market and similar securities having a rating of at least P-2 or A-2 from either Moody s or S&P, respectively, and in each case maturing within 24 months after the date of the creation thereof.

Cash Management Obligations means, with respect to any Person, any obligations of such Person to any lender in respect of treasury management arrangements, depositary or other cash management services, including any treasury management line of credit.

Change of Control means the occurrence of any of the following:

(1) the direct or indirect sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the properties or assets of the Company (including Equity Interests of Restricted Subsidiaries) and its Subsidiaries taken as a whole to any Person (including any person (as that term is used in Section 13(d)(3) of the Exchange Act)) other than any Permitted Holder;

(2) the adoption of a plan relating to the liquidation or dissolution of the Company; or

(3) the consummation of any transaction (including, without limitation, any merger or consolidation) the result of which is that any person (as defined above), other than any Permitted Holder, becomes the Beneficial Owner, directly or indirectly, of more than 50% of the Voting Stock of the Company, measured by voting power rather than number of shares, units or the like; provided that a transaction in which the Company becomes a Subsidiary of another Person shall not constitute a Change of Control if, immediately following such transaction, the persons (as defined above) who were Beneficial Owners of the Voting Stock of the Company immediately prior to such transaction Beneficially Own, directly or indirectly through one or more intermediaries, 50% or more of the total voting power of the Voting Stock of such other Person of whom the Company has become a Subsidiary.

Code means the Internal Revenue Code of 1986, as amended from time to time, and any successor statute or statutes thereto.

Consolidated Cash Flow means, with respect to any specified Person for any period, the Consolidated Net Income of such Person for such period plus, without duplication:

(1) an amount equal to any extraordinary expenses or loss plus any net loss realized by such Person or any of its Restricted Subsidiaries in connection with an Asset Sale, to the extent such expenses or losses were deducted in computing such Consolidated Net Income; *plus*

(2) provision for taxes based on income or profits (including state franchise taxes accounted for as income taxes in accordance with GAAP) or Permitted Tax Distributions of such Person and its Restricted Subsidiaries for such period, to the extent that such provision for taxes or Permitted Tax Distributions was deducted in computing such Consolidated Net Income; *plus*

(3) the Fixed Charges of such Person and its Restricted Subsidiaries for such period, to the extent that such Fixed Charges were deducted in computing such Consolidated Net Income; *plus*

(4) depreciation, depletion, amortization (including amortization of intangibles but excluding amortization of prepaid cash expenses that were paid in a prior period), impairment, abandonment expense, non-cash equity based compensation expense and other non-cash charges and expenses (excluding any such non-cash charge or expense to the extent that it represents an accrual of or reserve for cash charges or expenses in any future period or amortization of a prepaid cash charge or expense that was paid in a prior period) of such Person and its Restricted Subsidiaries for such period to the extent that such depreciation, depletion, amortization, impairment, abandonment expense and other non-cash charges or expenses were deducted in computing such Consolidated Net Income; *plus*

(5) if such Person accounts for its oil and gas operations using successful efforts or a similar method of accounting, consolidated exploration expense of such Person and its Restricted Subsidiaries; *minus*

(6) non-cash items increasing such Consolidated Net Income for such period, other than the accrual of revenue in the ordinary course of business; and *minus*

(7) to the extent increasing such Consolidated Net Income for such period, the sum of (a) the amount of deferred revenues that are amortized during such period and are attributable to reserves that are subject to Volumetric Production Payments and (b) amounts recorded in accordance with GAAP as repayments of principal and interest pursuant to Dollar-Denominated Production Payments,

in each case, on a consolidated basis and determined in accordance with GAAP.

Consolidated Net Income means, with respect to any specified Person for any period, the aggregate of the net income (loss) of such Person and its Restricted Subsidiaries for such period, on a consolidated basis determined in accordance with GAAP and without any reduction in respect of Preferred Stock dividends; *provided* that:

(1) the net income (or loss) of any Person that is not a Restricted Subsidiary or that is accounted for by the equity method of accounting will be included, but only to the extent of, in the case of net income, the amount of dividends or distributions paid in cash to the specified Person or a Restricted Subsidiary of the Person, or, in the case of net loss, the amount of cash that has been contributed by the specified Person or Restricted Subsidiary to fund such loss;

(2) the net income of any Restricted Subsidiary of such Person will be excluded to the extent that the declaration or payment of dividends or similar distributions by that Restricted Subsidiary of that net income is not at the date of determination permitted, directly or indirectly, by operation of the terms of its charter, or any judgment, decree, order, statute, rule or governmental regulation applicable to that Restricted Subsidiary or its stockholders, partners or members or any other loan instrument, agreement or other contractual restriction;

(3) the cumulative effect of a change in accounting principles will be excluded;

(4) any gain (loss), net of taxes (less all fees and expenses relating thereto), realized upon the sale or other disposition of any property, plant or equipment of such Person or its consolidated Restricted Subsidiaries (including pursuant to any sale or leaseback transaction) which is not sold or otherwise disposed of in the ordinary course of business and any gain (loss) realized upon the sale or other disposition of any Capital Stock of any Person, together with any related provision for taxes or Permitted Tax Distributions on any such gain, will be excluded;

(5) to the extent deducted in the calculation of Consolidated Net Income, any non-cash or other charges relating to any premium or penalty paid, write off of deferred financing costs or other financial recapitalization charges in connection with redeeming or retiring any Indebtedness prior to its Stated Maturity will be excluded;

(6) any ceiling limitation on Oil and Gas Properties or other asset impairment writedowns on Oil and Gas Properties or other non-current assets under GAAP or SEC guidelines will be excluded; and

(7) any unrealized non-cash gains or losses or charges in respect of Hedging Obligations (including those resulting from the application of FASB ASC 815) will be excluded; and

(8) for any period during which such person is a pass through entity for U.S. federal income tax purposes, an amount equal to the Permitted Tax Distributions for such period will be excluded.

Consolidated Net Working Capital means (a) all current assets of the Company and its Restricted Subsidiaries except current assets from Oil and Gas Hedging Contracts, less (b) all current liabilities of the Company and its Restricted Subsidiaries, except (i) current liabilities included in Indebtedness, (ii) current liabilities associated with future abandonment or asset retirement obligations relating to oil and natural gas properties and (iii) any current liabilities from Oil and Gas Hedging Contracts, in each case as set forth in the consolidated financial statements of the Company prepared in accordance with GAAP (excluding any adjustments made pursuant to FASB ASC 815).

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continuing means, with respect to any Default or Event of Default, that such Default or Event of Default has not been cured or waived.

Credit Agreement means that certain Credit Agreement, dated as of June 18, 2014, by and among the Company, as borrower, Bank of America N.A., as administrative agent, and the other financial institutions party thereto, including any related notes, Guarantees, collateral documents, instruments and agreements executed in connection therewith, and, in each case, as amended, restated, modified, renewed, refunded, replaced in any manner (whether upon or after termination or otherwise) or refinanced (including by means of sales of debt securities to institutional investors) in whole or in part from time to time.

Credit Facilities means one or more debt facilities (including, without limitation, the Credit Agreement), indentures or commercial paper facilities, in each case, with banks or other institutional lenders or institutional investors providing for revolving credit loans, term loans, capital market financings, receivables financing (including through the sale of receivables to such lenders or to special purpose entities formed to borrow from such lenders against such receivables), letters of credit, debt issuances or other borrowings, in each case, as amended, restated, modified, renewed, refunded, replaced in any manner (whether upon or after termination or otherwise) or refinanced (including refinancing with any capital markets transaction or otherwise by means of sales of debt securities to institutional investors) in whole or in part from time to time.

Customary Recourse Exceptions means, with respect to any Non-Recourse Debt of an Unrestricted Subsidiary, exclusions from the exculpation provisions with respect to such Non-Recourse Debt for the voluntary bankruptcy of such Unrestricted Subsidiary, fraud, misapplication of cash, environmental claims, waste, willful destruction and other circumstances customarily excluded by lenders from exculpation provisions or included in separate indemnification agreements in non-recourse financings.

Default means any event that is, or with the passage of time or the giving of notice or both would be, an Event of Default.

De Minimis Guaranteed Amount means a principal amount of Indebtedness that does not exceed $5.0 million.

Disqualified Stock means any Capital Stock that, by its terms (or by the terms of any security into which it is convertible, or for which it is exchangeable, in each case, at the option of the holder of the Capital Stock), or upon the happening of any event, matures or is mandatorily redeemable, pursuant to a sinking fund obligation or otherwise, or redeemable at the option of the holder of the Capital Stock, in whole or in part, on or prior to the date that is 91 days after the earlier of (a) the date on which no notes are outstanding and (b) the date on which the notes mature; *provided* that only the portion of Capital Stock which is mandatorily redeemable or matures or is redeemable at the option of the holder thereof prior to such date will be deemed to be Disqualified Stock; *provided further* that any Capital Stock issued pursuant to any plan of the Company or any of its Affiliates for the benefit of one or more employees will not constitute Disqualified Stock solely because it may be required to be repurchased by the Company or any of its Affiliates in order to satisfy applicable contractual, statutory or regulatory obligations. Notwithstanding the preceding sentence, any Capital Stock that would constitute Disqualified Stock solely because the holders of the Capital Stock have the right to require the Company to repurchase or redeem such Capital Stock upon the occurrence of a change of control or an asset sale will not constitute Disqualified Stock if (x) the terms of such Capital Stock provide that the Company may not repurchase or redeem any such Capital Stock pursuant to such provisions unless such repurchase or redemption complies with the covenant described above under the caption Certain Covenants Restricted Payments, or (y) the terms of such Capital Stock provide that the Company may not repurchase or redeem any such Capital Stock pursuant to such provisions prior to the Company s purchase of the notes as is required to be purchased pursuant to the provisions of the indenture. The amount (or principal amount) of Disqualified Stock deemed to be outstanding at any time for purposes of the indenture will be the maximum amount that the Company and its

Restricted Subsidiaries may become obligated to pay upon the maturity of, or pursuant to any mandatory redemption provisions of, such Disqualified Stock, exclusive of accrued dividends.

Dollar-Denominated Production Payments means production payment obligations recorded as liabilities in accordance with GAAP, together with all undertakings and obligations in connection therewith.

Domestic Subsidiary means any Restricted Subsidiary of the Company that was formed under the laws of the United States or any state of the United States or the District of Columbia.

Equity Interests of any Person means (1) any and all Capital Stock of such Person and (2) all rights to purchase, warrants or options (whether or not currently exercisable), participations or other equivalents of or interests in (however designated) such Capital Stock of such Person, but excluding from all of the foregoing any debt securities exercisable for, exchangeable for or convertible into Equity Interests, regardless of whether such debt securities include any right of participation with Equity Interests.

Equity Offering means a sale of Equity Interests of the Company (other than Disqualified Stock and other than to a Subsidiary of the Company) made for cash by the Company after the date of the indenture.

Exchange Notes means the notes issued in an Exchange Offer pursuant to the indenture. Such term includes the new notes.

Exchange Offer has the meaning set forth for such term in the applicable registration rights agreement.

Existing Indebtedness means all Indebtedness of the Company and its Subsidiaries (other than Indebtedness under the Credit Agreement and the PIK Notes) in existence on the date of the indenture, until such amounts are repaid.

Fair Market Value means the value that would be paid by a willing buyer to an unaffiliated willing seller in a transaction not involving distress or necessity of either party, determined in good faith by the Board of Directors of the Company in the case of amounts of $50.0 million or more and otherwise by an Officer of the Company (unless otherwise provided in the indenture), any such determination being conclusive for all purposes under the indenture.

Fixed Charge Coverage Ratio means with respect to any specified Person for any four-quarter reference period, the ratio of the Consolidated Cash Flow of such Person for such period to the Fixed Charges of such Person for such period. In the event that the specified Person or any of its Restricted Subsidiaries incurs, assumes, Guarantees, repays, repurchases, redeems, defeases or otherwise discharges any Indebtedness (other than ordinary working capital borrowings) or issues, repurchases or redeems Preferred Stock subsequent to the commencement of the period for which the Fixed Charge Coverage Ratio is being calculated and on or prior to the date on which the event for which the calculation of the Fixed Charge Coverage Ratio is made (the ***Calculation Date***), then the Fixed Charge Coverage Ratio will be calculated giving pro forma effect to such incurrence, assumption, Guarantee, repayment, repurchase, redemption, defeasance or other discharge of Indebtedness, or such issuance, repurchase or redemption of Preferred Stock, and the use of the proceeds therefrom, as if the same had occurred at the beginning of the applicable four-quarter reference period (except that in making such computation, the amount of Indebtedness under any revolving Credit Facility outstanding on the date of such determination will be deemed to be (i) the average daily balance of such Indebtedness during such four fiscal quarters or such shorter period for which such Credit Facility was outstanding or (ii) if such revolving Credit Facility was created after the end of such four fiscal quarters, the average daily balance of such Indebtedness during the period from the date of creation of such revolving Credit Facility to the date of such determination). If any Indebtedness bears a floating rate of interest and is being given pro forma effect, the interest expense on such Indebtedness will be calculated as if the average rate in effect from the beginning of such period to the Calculation Date had been the applicable rate for the entire period (taking into account any interest Hedging Obligation applicable to such Indebtedness, but if the remaining term of such interest Hedging Obligation is less than twelve months, then such interest Hedging Obligation shall only be taken into account for that portion of the period equal to the remaining term thereof). If any Indebtedness that is being given pro forma effect bears an interest rate at the option of such Person, the interest rate shall be calculated by applying such option rate chosen by such Person. Interest on Indebtedness that may optionally be determined at an interest rate based upon a factor of a prime or similar rate, a Eurocurrency interbank offered rate, or other rate, shall be deemed to have been based upon the rate actually chosen, or if none, then based upon such optional rate chosen as such Person may designate. Interest on any Indebtedness under a revolving Credit Facility will be calculated based upon the average daily balance of such Indebtedness during the applicable period.

In addition, for purposes of calculating the Fixed Charge Coverage Ratio:

(1) acquisitions or Investments that have been made, or contributions received, by the specified Person or any of its Restricted Subsidiaries, including through mergers, consolidations or otherwise (including acquisitions or Investments or contributions of assets used or useful in the Oil and Gas Business), or any Person or any of its Restricted Subsidiaries acquired by the specified Person or any of its Restricted Subsidiaries, and including all related financing transactions and including increases in ownership of Restricted Subsidiaries, during the four-quarter reference period or subsequent to such four-quarter reference period and on or prior to the Calculation Date, or that are to be made on the Calculation Date, will be given pro forma effect as if they had occurred on the first day of the four-quarter reference period;

(2) the Consolidated Cash Flow attributable to discontinued operations, as determined in accordance with GAAP, and operations or businesses or Investments (or ownership interests therein) disposed of on or prior to the Calculation Date, will be excluded;

(3) the Fixed Charges attributable to discontinued operations, as determined in accordance with GAAP, and operations or businesses or Investments (or ownership interests therein) disposed of on or prior to the Calculation Date, will be excluded, but only to the extent that the obligations giving rise to such Fixed Charges will not be obligations of the specified Person or any of its Restricted Subsidiaries following the Calculation Date;

(4) any Person that is to be a Restricted Subsidiary of the specified Person immediately following the Calculation Date will be deemed to have been a Restricted Subsidiary at all times during such four-quarter reference period;

(5) any Person that is not to be a Restricted Subsidiary of the specified Person immediately following the Calculation Date will be deemed not to have been a Restricted Subsidiary at any time during such four-quarter reference period;

(6) interest income reasonably anticipated by such Person to be received during the applicable four-quarter reference period from cash or Cash Equivalents held by such Person or any Restricted Subsidiary of such

Person, which cash or Cash Equivalents exist on the Calculation Date or will exist as a result of the transaction giving rise to the need to calculate the Fixed Charge Coverage Ratio, will be included; and

(7) if, since the beginning of such four-quarter reference period, any Person (that subsequently became a Restricted Subsidiary or was merged or consolidated with or into such Person or any of its Restricted Subsidiaries since the beginning of such four-quarter reference period) disposed of any operations or businesses or Investments (or ownership interests therein) or made any acquisition or Investment or received any contribution that would have required an adjustment pursuant to clause (1), (2) or (3) above if made by such Person or any of its Restricted Subsidiaries during such four-quarter reference period, Consolidated Cash Flow and Fixed Charges for such period will be calculated after giving pro forma effect thereto as if such disposition or acquisition, contribution or Investment had occurred on the first day of such four-quarter reference period.

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For purposes of this definition, whenever pro forma effect is to be given to any calculation under this definition, the pro forma calculations will be determined in good faith by a responsible financial or accounting Officer of the Company, which determination shall be conclusive for all purposes under the indenture; *provided* that such Officer may in such Officer s discretion include any reasonably identifiable and factually supportable pro forma changes to Consolidated Cash Flow or Fixed Charges, including any pro forma expense and cost reductions or synergies that have occurred or are reasonably expected to occur within the 12 months immediately following the Calculation Date (regardless of whether those cost savings or operating improvements could then be reflected in pro forma financial statements in accordance with Regulation S-X promulgated under the Securities Act or any other regulation or policy of the SEC related thereto).

Fixed Charges means, with respect to any specified Person for any period, the sum, without duplication, of:

(1) the consolidated interest expense (less interest income) of such Person and its Restricted Subsidiaries for such period, whether paid or accrued (excluding (i) any interest attributable to Dollar-Denominated Production Payments, (ii) write-off of deferred financing costs and (iii) accretion of interest charges on future plugging and abandonment obligations, future retirement benefits and other obligations that do not constitute Indebtedness, but including, without limitation, amortization of debt issuance costs and original issue discount, non-cash interest payments, the interest component of all payments associated with Capital Lease Obligations, imputed interest with respect to Attributable Debt, commissions, discounts and other fees and charges incurred in respect of letter of credit or bankers acceptance financings), and net of the effect of all payments made or received pursuant to Hedging Obligations in respect of interest rates; *plus*

(2) the consolidated interest expense of such Person and its Restricted Subsidiaries that was capitalized during such period; *plus*

(3) any interest on Indebtedness of another Person (other than Non-Recourse Debt of any Unrestricted Subsidiary or Joint Venture incurred pursuant to clause (14)(b) of the covenant described under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock) that is Guaranteed by such Person or one of its Restricted Subsidiaries or secured by a Lien on assets of such Person or one of its Restricted Subsidiaries, whether or not such Guarantee or Lien is called upon; *plus*

(4) all dividends, whether paid or accrued and whether or not in cash, on any series of Disqualified Stock of such Person or any series of Preferred Stock of its Restricted Subsidiaries, other than dividends on Equity Interests payable solely in Equity Interests of such Person (other than Disqualified Stock) or to such Person or a Restricted Subsidiary of such Person,

in each case, on a consolidated basis and determined in accordance with GAAP.

Foreign Subsidiary means any Restricted Subsidiary of the Company that is not a Domestic Subsidiary.

GAAP means generally accepted accounting principles in the United States, which are in effect from time to time. All ratio computations based on GAAP contained in the indenture will be computed in conformity with GAAP.

Guarantee means a guarantee other than by endorsement of negotiable instruments for collection in the ordinary course of business, direct or indirect, in any manner including, without limitation, by way of a pledge of assets or through letters of credit or reimbursement agreements in respect thereof, of all or any part of any Indebtedness (whether arising by virtue of partnership arrangements, or by agreements to keep-well, to purchase assets, goods, securities or services, to take or pay or to maintain financial statement conditions or otherwise). When used as a verb, Guarantee has a correlative meaning.

Guarantors means any Subsidiary of the Company that Guarantees the Notes in accordance with the provisions of the indenture, and their respective successors and assigns, in each case, until the Note Guarantee of such Person has been released in accordance with the provisions of the indenture.

Hedging Obligations means, with respect to any specified Person, the obligations of such Person under any (a) Interest Rate Agreement and (b) Oil and Gas Hedging Contract.

Hydrocarbons means oil, natural gas, casing head gas, drip gasoline, natural gasoline, condensate, distillate, liquid hydrocarbons, gaseous hydrocarbons and all constituents, elements or compounds thereof and products refined or processed therefrom.

Indebtedness means, with respect to any specified Person, any indebtedness of such Person (excluding accrued expenses and Trade Payables), whether or not contingent:

(1) in respect of borrowed money;

(2) (a) evidenced by bonds, notes, debentures or similar instruments or (b) constituting letters of credit (or reimbursement agreements in respect thereof) (other than obligations with respect to letters of credit securing obligations (other than obligations described in clauses (1), (2)(a), (3), (4) or (6) of this definition) entered into in the ordinary course of business of such Person to the extent such letters of credit are not drawn upon or, if and to the extent drawn upon, such drawing is reimbursed no later than the tenth Business Day following payment on the letter of credit);

(3) in respect of bankers acceptances;

(4) representing Capital Lease Obligations or Attributable Debt in respect of sale and leaseback transactions;

(5) representing the balance deferred and unpaid of the purchase price of any property or services due more than six months after such property is acquired or such services are completed; or

(6) representing any Hedging Obligations,

if and to the extent any of the preceding items (other than letters of credit, Attributable Debt and Hedging Obligations) would appear as a liability upon a balance sheet of the specified Person prepared in accordance with GAAP. In addition, the term Indebtedness includes all Indebtedness of others secured by a Lien on any asset of the specified Person (whether or not such Indebtedness is assumed by the specified Person) and, to the extent not otherwise included, the Guarantee by the specified Person of any Indebtedness of any other Person (including, with respect to any Production Payment, any warranties or guarantees of production or payment by such Person with respect to such Production Payment, but excluding other contractual obligations of such Person with respect to such Production Payment). Subject to the preceding sentence, neither Dollar-Denominated Production Payments nor Volumetric Production Payments shall be deemed to be Indebtedness.

In addition, Indebtedness of any Person shall include Indebtedness described in the preceding paragraph that would not appear as a liability on the balance sheet of such Person if:

(1) such Indebtedness is the obligation of a partnership that is a Joint Venture;

(2) such Person or a Restricted Subsidiary of such Person is a general partner of the Joint Venture (a ***Joint Venture General Partner***); and

(3) there is recourse, by contract or operation of law, with respect to the payment of such Indebtedness to property or assets of such Person or a Restricted Subsidiary of such Person; and then such Indebtedness shall be included in an amount not to exceed:

(a) the lesser of (i) the net assets of the Joint Venture General Partner and (ii) the amount of such obligations to the extent that there is recourse, by contract or operation of law, to the property or assets of such Person or a Restricted Subsidiary of such Person; or

(b) if less than the amount determined pursuant to clause (a) immediately above, the actual amount of such Indebtedness that is recourse to such Person or a Restricted Subsidiary of such Person, if the

Indebtedness is evidenced by a writing and is for a determinable amount and the related interest expense shall be included in Fixed Charges to the extent actually paid by such Person or its Restricted Subsidiaries.

Notwithstanding the foregoing, the following shall not in any event constitute Indebtedness :

(1) any indebtedness which has been defeased or discharged in accordance with GAAP or defeased or discharged pursuant to the deposit of cash or Cash Equivalents (in an amount sufficient to satisfy all such indebtedness at maturity or redemption, as applicable, and all payments of interest and premium, if any) in a trust or account created or pledged for the sole benefit of the holders of such indebtedness, and subject to no other Liens, and the other applicable terms of the instrument governing such indebtedness;

(2) any obligation of a Person in respect of a farm-in agreement or similar arrangement whereby such Person agrees to pay all or a share of the drilling, completion or other expenses of an exploratory or development well (which agreement may be subject to a maximum payment obligations, after which expenses are shared in accordance with the working or participation interest therein or in accordance with the agreement of the parties) or perform the drilling, completion or other operation on such well in exchange for an ownership interest in an oil or gas property;

(3) any unrealized losses or charges in respect of Interest Rate Agreements or Oil and Gas Hedging Contracts (including those resulting from the application of FASB ASC 815);

(4) all contracts and other obligations, agreements, instruments or arrangements described in clauses (10), (18) and (19) of the definition of Permitted Liens ; and

(5) Cash Management Obligations.

Interest Rate Agreement means any interest rate swap agreement (whether from fixed to floating or from floating to fixed), interest rate cap agreement, interest rate collar agreement or other similar agreement or arrangement designed to protect the Company or any of its Restricted Subsidiaries against fluctuations in interest rates and is not for speculative purposes.

Investment Grade Rating means a rating equal to or higher than Baa3 (or the equivalent) by Moody s or BBB- (or the equivalent) by S&P.

Investments means, with respect to any Person, all direct or indirect investments by such Person in other Persons (including Affiliates) in the forms of loans (including Guarantees), advances or capital contributions, and purchases or other acquisitions for consideration of Indebtedness, Equity Interests or other securities, together with all items that are or would be classified as investments on a balance sheet prepared in accordance with GAAP (excluding, in each case, (1) commission, travel and similar advances to officers and employees made in the ordinary course of business, (2) any interest in an oil or natural gas leasehold to the extent constituting a security under applicable law and (3) advances to customers in the ordinary course of business that are recorded as accounts receivable on the balance sheet of the lender, prepaid expenses or deposits and extensions of trade credit on commercially reasonable terms in accordance with normal trade practices). If the Company or any Restricted Subsidiary of the Company sells or otherwise disposes of any Equity Interests of any direct or indirect Restricted Subsidiary of the Company such that, after giving effect to any such sale or disposition, such Person is no longer a Restricted Subsidiary of the Company (other than the sale of all of the outstanding Capital Stock of such Subsidiary), the Company will be deemed to have made an Investment on the date of any such sale or disposition equal to the Fair Market Value of the Company s Investments in such Subsidiary that were not sold or disposed of in an amount determined as provided in the penultimate paragraph of the covenant described above under the caption Certain Covenants Restricted Payments. The acquisition by the Company or any Restricted Subsidiary of the Company of a Person that holds an Investment in a third Person will be deemed to be an Investment by the Company or such Restricted Subsidiary in such third Person in an amount equal to the Fair

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Market Value of the Investments held by the acquired Person in such third Person in an amount determined as provided in the final paragraph of the covenant described above under the caption Certain Covenants Restricted Payments. Except as otherwise provided in the indenture, the amount of an Investment will be determined at the time the Investment is made and without giving effect to subsequent changes in value or write-ups, write-downs or write-offs with respect to such Investment.

Joint Venture means any Person that is not a direct or indirect Subsidiary of the Company in which the Company or any of its Restricted Subsidiaries makes any Investment.

Legal Holiday means a Saturday, a Sunday or a day on which banking institutions in the City of Houston, Texas or the City of New York, New York are authorized by law, regulation or executive order to remain closed.

Lien means, with respect to any asset, any mortgage, lien, pledge, charge, security interest or encumbrance of any kind in respect of such asset, whether or not filed, recorded or otherwise perfected under applicable law, including any conditional sale or other title retention agreement, any lease in the nature thereof, any option or other agreement to sell or give a security interest in and any filing of or agreement to give any financing statement under the Uniform Commercial Code (or equivalent statutes) of any jurisdiction other than a precautionary financing statement respecting a lease not intended as a security agreement.

Measurement Date means December 18, 2013, the original issue date of the PIK Notes.

MLP means Memorial Production Partners LP, a Delaware limited partnership, and its successors.

MLP Asset Transfer means the direct or indirect sale, conveyance, transfer or other disposition of property or assets (including any Equity Interests of any Person) by the Company or any Restricted Subsidiary to the MLP or one of its Subsidiaries.

MLP General Partner means Memorial Production Partners GP LLC, a Delaware limited liability company and general partner of the MLP, and its successors and permitted assigns under the MLP s partnership agreement as general partner of the MLP.

MRD LLC means Memorial Resource Development LLC, a Delaware limited liability company and the accounting predecessor to the Company.

Moody s means Moody s Investors Service, Inc. and any successor to the ratings business thereof.

Net Proceeds means the aggregate cash proceeds and Cash Equivalents received by the Company or any of its Restricted Subsidiaries in respect of any Asset Sale (including, without limitation, any cash or Cash Equivalents received upon the sale or other disposition of any non-cash consideration received in any Asset Sale but excluding any non-cash consideration deemed to be cash or Cash Equivalents for purposes of the Asset Sales provisions of the indenture), net of (i) the costs relating to such Asset Sale, including, without limitation, legal, title and recording expenses, accounting and investment banking fees, and sales commissions, (ii) distributions and other payments required to be made to minority interest holders in Subsidiaries or joint ventures as a result of such Asset Sale, (iii) any relocation expenses and severance and associated costs, expenses and charges of personnel relating to the assets subject to or incurred as a result of the Asset Sale, (iv) taxes paid or payable as a result of the Asset Sale, in each case, after taking into account any available tax credits or deductions and any tax sharing arrangements, (v) amounts required to be applied to the repayment of Indebtedness (other than revolving credit Indebtedness under a Credit Facility that is secured by a Lien on the asset or assets that were the subject of such Asset Sale), and (vi) any reserve for adjustment or indemnification obligations in respect of the sale price of such asset or assets established in accordance with GAAP.

New Note Guarantee means the Guarantee by each Guarantor of the Company s obligations under the indenture and the new notes, as provided in the indenture.

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new notes means the notes issued in an Exchange Offer pursuant to the indenture.

NGP Energy Capital Management means NGP Energy Capital Management, L.L.C., a Texas limited liability company, and its successors.

Non-Recourse Debt means, with respect to Indebtedness of any Unrestricted Subsidiary or Joint Venture, Indebtedness:

(1) as to which neither the Company nor any of its Restricted Subsidiaries (a) provides credit support of any kind (including any undertaking, agreement or instrument that would constitute Indebtedness) or (b) is directly or indirectly liable as a guarantor or otherwise, except for Customary Recourse Exceptions and except by the pledge of (or a Guaranty limited in recourse solely to) the Equity Interests of such Unrestricted Subsidiary or Joint Venture; and

(2) as to which the lenders will not have any recourse to the Capital Stock or assets of the Company or any of its Restricted Subsidiaries (other than the Equity Interests of such Unrestricted Subsidiary or Joint Venture), except for Customary Recourse Exceptions.

Note Guarantee means the Guarantee by each Guarantor of the Company s obligations under the indenture and the notes, as provided in the indenture.

Obligations means any principal, interest, penalties, fees, indemnifications, reimbursements, damages and other liabilities payable under the documentation governing any Indebtedness.

Officer means, with respect to any Person, the Chairman of the Board, the Chief Executive Officer, the President, the Chief Operating Officer, the Chief Financial Officer, the Chief Accounting Officer, the Treasurer, any Assistant Treasurer, the Controller, the Secretary, any Assistant Secretary or any Vice President of such Person (or, if such Person is a limited partnership, the Chairman of the Board, the Chief Executive Officer, the President, the Chief Operating Officer, the Chief Financial Officer, the Chief Accounting Officer, the Treasurer, any Assistant Treasurer, the Controller, the Secretary, any Assistant Secretary or any Vice President of such Person s general partner).

Oil and Gas Business means (i) the acquisition, exploration, development, production, operation and disposition of interests in oil, gas and other Hydrocarbon properties, (ii) the gathering, marketing, treating, processing, storage, selling and transporting of any production from such interests or properties, (iii) any business relating to exploration for or development, production, treatment, processing, storage, transportation or marketing of oil, gas and other minerals and products produced in association therewith and (iv) any activity that, as determined in good faith by the Company, arises from, relates to or is ancillary, complementary or incidental to or necessary or appropriate for the activities described in clauses (i) through (iii) of this definition.

Oil and Gas Hedging Contracts means any puts, cap transactions, floor transactions, collar transactions, forward contract, commodity swap agreement, commodity option agreement or other similar agreement or arrangement in respect of Hydrocarbons to be purchased, used, produced, processed or sold by the Company or any of its Restricted Subsidiary that are customary in the Oil and Gas Business and designed to protect against price risks, basis risks or other risks encountered in the Oil and Gas Business and not for speculative purposes.

Oil and Gas Properties means all properties, including equity or other ownership interest therein, owned by such Person or any of its Restricted Subsidiaries which contain or are believed to contain proved oil and gas reserves as defined in Rule 4-10 of Regulation S-X of the Securities Act.

Omnibus Agreement means the Omnibus Agreement, dated as of December 14, 2011, among MRD LLC, the MLP General Partner and the MLP, as the same may be further amended or supplemented from time to time.

Permitted Acquisition Indebtedness means Indebtedness or Disqualified Stock or Preferred Stock of the Company or any of its Restricted Subsidiaries to the extent such Indebtedness or Disqualified Stock or Preferred Stock was Indebtedness or Disqualified Stock or Preferred Stock of any other Person existing at the time (a) such Person became a Restricted Subsidiary of the Company or (b) such Person was merged or consolidated with or into the Company or any of its Restricted Subsidiaries, and in each case was not incurred in contemplation of the foregoing, *provided* that on the date such Person became a Restricted Subsidiary or the date such Person was merged or consolidated with or into the Company or any of its Restricted Subsidiaries, as applicable, either of:

(1) immediately after giving effect to such transaction and any related financing transaction on a pro forma basis as if the same had occurred at the beginning of the applicable four-quarter period, the Company or such Person (if the Company is not the survivor in the transaction) would be permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ; or

(2) immediately after giving effect to such transaction and any related financing transaction on a pro forma basis as if the same had occurred at the beginning of the applicable four-quarter period, the Fixed Charge Coverage Ratio of the Company or such Person (if the Company is not the survivor in the transaction) is equal to or greater than the Fixed Charge Coverage Ratio of the Company immediately prior to such transaction.

Permitted Business Investments means Investments made in the ordinary course of, or of a nature that is or shall have become customary in, the Oil and Gas Business as a means of actively exploiting, exploring for, acquiring, developing, processing, gathering, marketing or transporting oil and natural gas through agreements, transactions, interests or arrangements which permit one to share risks or costs, comply with regulatory requirements regarding local ownership or satisfy other objectives customarily achieved through the conduct of Oil and Gas Business jointly with third parties, including, without limitation, (i) ownership interests in oil, natural gas, other Hydrocarbon properties or any interest therein or gathering, transportation, processing, storage or related systems, (ii) entry into and Investments and expenditures in the form of or pursuant to operating agreements, processing agreements, farm-in agreements, farm-out agreements, development agreements, area of mutual interest agreements, unitization agreements, pooling agreements, joint bidding agreements, service contracts, joint venture agreements, partnership agreements (whether general or limited), subscription agreements, stock purchase agreements and other similar or customary agreements, (iii) working interests, royalty interests, mineral leases, production sharing agreements, production sales and marketing agreements, oil or gas leases, overriding royalty agreements, net profits agreements, production payment agreements or royalty trust agreements, (iv) Investments of operating funds on behalf of co-owners of properties used in the Oil and Gas Business of the Company or its Restricted Subsidiaries pursuant to joint operating agreements, and (v) direct or indirect ownership interests in drilling rigs, fracturing units and other related equipment.

Permitted Holders means each of (i) MRD Holdco LLC, (ii) NGP Energy Capital Management, Natural Gas Partners VIII, L.P., Natural Gas Partners IX, L.P. and NGP IX Offshore Holdings, L.P., (iii) any affiliated funds or investment vehicles managed by any of the persons described in clause (ii) above, and any general partner, managing member, principal or managing director of any of the persons described in clause (ii) above, and (iv) the Company or any of its Restricted Subsidiaries.

Permitted Investments means:

(1) any Investment in the Company (including, without limitation, through the purchase of any notes) or in a Restricted Subsidiary of the Company;

(2) any Investment in cash and Cash Equivalents;

(3) any Investment by the Company or any Restricted Subsidiary of the Company in a Person, if as a result of such Investment:

(a) such Person becomes a Restricted Subsidiary of the Company; or

(b) such Person is merged, consolidated or amalgamated with or into, or transfers or conveys substantially all of its properties or assets to, or is liquidated into, the Company or a Restricted Subsidiary of the Company;

(4) any Investment made as a result of the receipt of non-cash consideration from an Asset Sale or Asset Swap that was made pursuant to and in compliance with the covenant described above under the caption Repurchase at the Option of Holders Asset Sales ;

(5) any acquisition of assets or Capital Stock solely in exchange for the issuance of, or with or out of the net cash proceeds of the substantially concurrent (a) contribution (other than from a Restricted Subsidiary) to the equity capital of the Company in respect of, or (b) sale (other than to a Restricted Subsidiary) of, Equity Interests (other than Disqualified Stock) of the Company, *provided* that in each such case, the amount of such issuance, contribution or sale will be disregarded for purposes of clause (c)(ii) under the caption Certain Covenants Restricted Payments ;

(6) any Investments received in compromise or resolution of (a) obligations of trade creditors or customers that were incurred in the ordinary course of business of the Company or any of its Restricted Subsidiaries, including pursuant to any plan of reorganization or similar arrangement upon the bankruptcy or insolvency of any trade creditor or customer; or (b) litigation, arbitration or other disputes;

(7) Investments represented by Hedging Obligations;

(8) Investments in any Person to the extent such Investments consist of prepaid expenses, negotiable instruments held for collection and lease, utility and workers compensation, performance and other deposits made in the ordinary course of business by the Company or any of its Restricted Subsidiaries;

(9) relocation allowances for, and loans or advances to, officers, directors or employees made in the ordinary course of business of the Company or any Restricted Subsidiary of the Company;

(10) repurchases of the notes or Note Guarantees;

(11) any Guarantee of Indebtedness of (a) the Company or a Restricted Subsidiary or (b) any Person that is not an Affiliate of the Company, in each case permitted to be incurred by the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ;

(12) any Investment existing on, or made pursuant to binding commitments existing on, the date of the indenture and any Investment consisting of an extension, modification or renewal of any Investment existing on, or made pursuant to a binding commitment existing on, the date of the indenture; *provided* that the amount of any such Investment may be increased (a) as required by the terms of such Investment as in existence on the

date of the indenture or (b) as otherwise permitted under the indenture;

(13) Investments acquired after the date of the indenture as a result of the acquisition by the Company or any Restricted Subsidiary of the Company of another Person, including by way of a merger or consolidation with or into the Company or any of its Restricted Subsidiaries in a transaction that is not prohibited by the covenant described above under the caption Certain Covenants Merger, Consolidation or Sale of Assets after the date of the indenture to the extent that such Investments were not made in contemplation of such acquisition, merger or consolidation and were in existence on the date of such acquisition, merger or consolidation;

(14) Permitted Business Investments or Permitted Other Business Investments;

(15) Investments received as a result of a foreclosure by, or other transfer of title to, the Company or any of its Restricted Subsidiaries with respect to any secured Investment in default;

(16) receivables owing to the Company or any Restricted Subsidiary created or acquired in the ordinary course of business and payable or dischargeable in accordance with customary trade terms; *provided*,

however, that such trade terms may include such concessionary trade terms as the Company or any such Restricted Subsidiary deems reasonable under the circumstances;

(17) professional or advisory, administrative, management, treasury or similar services, indemnification, insurance, officers and directors fees and expenses, registration fees and other like expenses paid or provided for the benefit of any Joint Venture or Unrestricted Subsidiary pursuant to arrangements not involving the incurrence of Indebtedness that comply with the covenant described under the caption Certain Covenants Transactions with Affiliates ;

(18) Investments consisting of Oil and Gas Hedging Contracts or Interest Rate Agreements permitted under the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ;

(19) Guarantees or other Investments arising from the incurrence of Indebtedness by the Company or any Restricted Subsidiary with respect to Indebtedness of any Unrestricted Subsidiary or Joint Venture permitted under clause (14) of the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ;

(20) Guarantees of performance or other obligations (other than Indebtedness) arising in the ordinary course in the Oil and Gas Business, including obligations under oil and natural gas exploration, development, joint operating, and related agreements and licenses, concessions or operating leases related to the Oil and Gas Business;

(21) advances and prepayments for asset purchases in the ordinary course of business in the Oil and Gas Business of the Company or any Restricted Subsidiary;

(22) any Investment in the Oil and Gas Business having an aggregate Fair Market Value (measured on the date such Investment was made and without giving effect to subsequent changes in value) that, when taken together with the Fair Market Value (as so measured) of all other Investments made pursuant to this clause (22) that are at the time outstanding, that does not exceed the greater of (a) $75.0 million and (b) 7.5% of Adjusted Consolidated Net Tangible Assets determined at the time such Investment is made; *provided*, *however*, that if any Investment pursuant to this clause (22) is made in any Person that is not a Restricted Subsidiary of the Company at the date of the making of such Investment and such Person becomes a Restricted Subsidiary of the Company after such date, such Investment shall thereafter be deemed to have been made pursuant to clause (1) above and shall cease to have been made pursuant to this clause (22) for so long as such Person continues to be a Restricted Subsidiary of the Company (unless the Company otherwise classifies such Investment in compliance with the indenture);

(23) any Investment in any Person having an aggregate Fair Market Value (measured on the date such Investment was made and without giving effect to subsequent changes in value) that, when taken together with the Fair Market Value (as so measured) of all other Investments made pursuant to this clause (23) that are at the time

outstanding, that does not exceed the greater of (a) $100.0 million and (b) 7.5% of Adjusted Consolidated Net Tangible Assets determined at the time such Investment is made; *provided*, *however*, that if any Investment pursuant to this clause (23) is made in any Person that is not a Restricted Subsidiary of the Company at the date of the making of such Investment and such Person becomes a Restricted Subsidiary of the Company after such date, such Investment shall thereafter be deemed to have been made pursuant to clause (1) above and shall cease to have been made pursuant to this clause (23) for so long as such Person continues to be a Restricted Subsidiary of the Company (unless the Company otherwise classifies such Investment in compliance with the indenture); and

(24) Investments by the MLP General Partner to maintain a 0.1% general partnership interest in the MLP.

With respect to any Investment, the Company may, in its sole discretion, classify all or any portion of any Investment in one or more of the above clauses so that the entire Investment is a Permitted Investment.

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Permitted Liens means:

(1) Liens on assets of the Company or any Restricted Subsidiary securing Indebtedness under Credit Facilities that was permitted by the terms of the indenture to be incurred;

(2) Liens in favor of the Company or the Guarantors;

(3) Liens on property of a Person existing at the time such Person becomes a Restricted Subsidiary of the Company or is merged with or into or consolidated with the Company or any Restricted Subsidiary of the Company; *provided* that such Liens were in existence prior to the contemplation of such Person becoming a Restricted Subsidiary of the Company or such merger or consolidation and do not extend to any assets other than those of the Person that becomes a Restricted Subsidiary of the Company or is merged with or into or consolidated with the Company or any Restricted Subsidiary of the Company;

(4) Liens on property (including Capital Stock) existing at the time of acquisition of the property by the Company or any Subsidiary of the Company; *provided* that such Liens were in existence prior to such acquisition and not incurred in contemplation of such acquisition;

(5) pledges or deposits or other Liens to secure the performance of statutory obligations, insurance, surety or appeal bonds, workers compensation, unemployment and similar obligations, bid, leases (including, without limitation, statutory and common law landlord s liens), government contracts, plugging and abandonment obligations and performance bonds or other obligations of a like nature incurred in the ordinary course of business (including Liens to secure letters of credit issued to assure payment of such obligations);

(6) Liens securing Indebtedness incurred pursuant to clause (4) of the definition of Permitted Debt ; *provided* that (a) such Liens are in favor of the seller or other transferor of such asset or property, in favor of the Person or Persons designing, constructing, installing, developing, repairing or improving such asset or property, or in favor of the Person or Persons that provided the funding for the acquisition, design, construction, installation, development, repair or improvement cost, as the case may be, of such asset or property, (b) such Liens are created no later than 360 days after the acquisition, design, construction, installation, development, repair or improvement, (c) the aggregate principal amount of the Indebtedness secured by such Liens is otherwise permitted to be incurred under the indenture and does not exceed the greater of (i) the cost of the asset or property so acquired, designed, constructed, installed, developed, repaired or improved plus related financing costs and (ii) the fair market value of the asset or property so acquired, designed, constructed, installed, developed, repaired or improved, measured at the date of such acquisition, or the date of completion of such design, construction, installation, development, repair or improvement plus related financing costs, and (d) such Liens are limited to the asset or property so acquired, designed, constructed, installed, developed, repaired or improved (together with improvements, additions, accessions and contractual rights relating primarily thereto and all proceeds thereof (including dividends, distributions and increases in respect thereof));

(7) Liens existing on the date of the indenture (and not referred to in clause (1) of this definition);

(8) Liens created for the benefit of (or to secure) the notes (or the Note Guarantees) or to secure other obligations under the indenture;

(9) Liens on and pledges of the Equity Interests of any Unrestricted Subsidiary or any Joint Venture owned by the Company or any Restricted Subsidiary of the Company to the extent securing Non-Recourse Debt or other Indebtedness of such Unrestricted Subsidiary or Joint Venture;

(10) Liens on pipelines or pipeline facilities that arise by operation of law;

(11) Liens reserved in oil and natural gas mineral leases for bonus or rental payments and for compliance with the terms of such leases;

(12) Liens to secure any Indebtedness incurred to refinance or replace Indebtedness described under clauses (3), (4), (6) and (7) permitted to be incurred under the indenture; *provided*, *however*, that:

(a) the new Lien is limited to all or part of the same property and assets that secured or, under the written agreements pursuant to which the original Lien arose, could secure the original Lien (plus improvements and accessions to, such property or proceeds or distributions thereof); and

(b) the Indebtedness secured by the new Lien is not increased to any amount greater than the sum of (x) the outstanding principal amount, or, if greater, committed amount, of the Indebtedness exchanged, renewed, refunded, refinanced, replaced, defeased or discharged with such Permitted Refinancing Indebtedness and (y) an amount necessary to pay any fees and expenses, including premiums, related to such exchange, renewal, refunding, refinancing, replacement, defeasance or discharge;

(13) Liens on insurance policies and proceeds thereof, or other deposits, to secure insurance premium financings;

(14) filing of Uniform Commercial Code financing statements as a precautionary measure in connection with operating leases;

(15) bankers Liens, rights of setoff, rights of revocation, refund or chargeback with respect to money or instruments of the Company or any Restricted Subsidiary, Liens arising out of judgments or awards not constituting an Event of Default and notices of lis pendens and associated rights related to litigation being contested in good faith by appropriate proceedings and for which adequate reserves have been made;

(16) Liens on cash, Cash Equivalents or other property arising in connection with the defeasance, discharge or redemption of Indebtedness;

(17) Liens on specific items of inventory or other goods (and the proceeds thereof) of any Person securing such Person s obligations in respect of bankers acceptances issued or created in the ordinary course of business for the account of such Person to facilitate the purchase, shipment or storage of such inventory or other goods;

(18) Liens in respect of Production Payments and Reserve Sales; *provided* that such Liens are limited to the property that is subject to such Production Payments and Reserve Sales;

(19) Liens arising under oil and natural gas leases or subleases, overriding royalty interests, assignments, farm-out agreements, farm-in agreements, division orders, contracts for the sale, purchase, exchange, transportation, gathering or processing of Hydrocarbons, unitizations and pooling designations, declarations, orders and agreements, development agreements, joint venture agreements, partnership agreements, operating agreements, royalties, working interests, net profits interests, joint interest billing arrangements, participation agreements, production sales contracts, production payment agreements, royalty trust agreements, incentive compensation programs for geologists, geophysicists and other providers of technical services to the Company or a Restricted Subsidiary, area of mutual interest agreements, gas balancing or deferred production agreements, injection, repressuring and recycling agreements, salt water or other disposal agreements, seismic or geophysical permits or agreements, licenses, sublicenses and other

agreements which are customary in the Oil and Gas Business; *provided*, *however*, in all instances that such Liens are limited to the assets that are the subject of the relevant agreement, program, order or contract;

(20) Liens to secure performance of Hedging Obligations of the Company or any of its Restricted Subsidiaries entered into in the ordinary course of business and not for speculative purposes;

(21) Liens arising under the indenture in favor of the trustee for its own benefit and similar Liens in favor of other trustees, agents and representatives arising under instruments governing Indebtedness permitted to be incurred under the indenture; *provided*, *however*, that such Liens are solely for the benefit of the trustees, agents or representatives in their capacities as such and not for the benefit of the holders of such Indebtedness;

(22) any Lien incurred by the Company or any Restricted Subsidiary of the Company with respect to Indebtedness in aggregate principal amount that, when taken together with the aggregate principal amount of all other Indebtedness secured by Liens incurred pursuant to this clause (22) then outstanding, does not exceed the greater of (a) $75.0 million and (b) 5.0% of Adjusted Consolidated Net Tangible Assets determined at the time such Lien is incurred;

(23) leases and subleases of real property which do not materially interfere with the ordinary conduct of the business of the Company or the Restricted Subsidiaries;

(24) any Lien arising by reason of:

(a) taxes, assessments or governmental charges or claims that are not yet delinquent or which are being contested in good faith by appropriate proceedings promptly instituted and diligently conducted; *provided* that any reserve or other appropriate provision as will be required in conformity with GAAP will have been made therefor,

(b) good faith deposits in connection with tenders, leases and contracts (other than contracts for the payment of Indebtedness),

(c) survey exceptions, zoning restrictions, easements, licenses, reservations, title defects, rights of others for rights of way, utilities, sewers, electric lines, telephone or telegraph lines, and other similar purposes, provisions, covenants, conditions, waivers, restrictions on the use of property or minor irregularities of title (and with respect to leasehold interests, mortgages, obligations, Liens and other encumbrances incurred, created, assumed or permitted to exist and arising by, through or under a landlord or owner of the leased property, with or without consent of the lessee), none of which materially impairs the use of any parcel of property material to the operation of the business of the Company or the Restricted Subsidiaries or the value of such property for the purpose of such business,

(d) operation of law or contract in favor of mechanics, carriers, warehousemen, landlords, materialmen, laborers, employees, suppliers and similar persons, incurred in the ordinary course of business, to the extent such Liens relate only to the tangible property of the lessee which is located on such property, for sums which are not yet delinquent or are being contested in good faith by negotiations or by appropriate proceedings which suspend the collection thereof; if such reserve or other appropriate provision, if any, as shall be required by GAAP shall have been made in respect thereof, or

(e) normal depository or cash-management arrangements with banks; and

(25) Liens on any specific property or any interest therein, construction thereon or improvement thereto to secure all or any part of the costs incurred for surveying, exploration, drilling, extraction, development, operation, production, construction, alteration, repair or improvement of, in, from, under or on such property and the

plugging and abandonment of wells located thereon (it being understood that, in the case of oil and gas producing properties, or any interest therein, costs incurred for development and production shall include costs incurred for all facilities relating to such properties or to projects, ventures or other arrangements of which such properties form a part or which relate to such properties or interests and costs incurred for processing, gathering, marketing, refining and storage of such production), in each case that do not secure Indebtedness for borrowed money.

In each case set forth above, notwithstanding any stated limitation on the assets that may be subject to such Lien, a Permitted Lien on a specified asset or group or type of assets shall also include any Lien on all improvements, additions, accessions and contractual rights relating primarily thereto and all proceeds thereof (including dividends, distributions and increases in respect thereof).

Permitted Other Business Investments means Investments by the Company or any of its Restricted Subsidiaries in any Person (including in any Unrestricted Subsidiary or Joint Venture); *provided* that:

(1) at the time of any such Investment and immediately thereafter, the Company would be permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio set forth in the first paragraph of the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ;

(2) if such Person has outstanding Indebtedness at the time of any such Investment, either (a) all such Indebtedness is Non-Recourse Debt or (b) any such Indebtedness of such Person that is not Non-Recourse Debt could, at the time such Investment is made, be incurred at that time by the Company and its Restricted Subsidiaries pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described above under the caption Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock ; and

(3) such Person is not engaged, in any material respect, in any business other than the Oil and Gas Business.

Permitted Refinancing Indebtedness means any Indebtedness or Disqualified Stock or Preferred Stock of the Company or any of its Restricted Subsidiaries issued in exchange for, or the net proceeds of which are used to renew, refund, refinance, replace, defease or discharge other Indebtedness or Disqualified Stock or Preferred Stock of the Company or any of its Restricted Subsidiaries (other than intercompany Indebtedness); *provided* that:

(1) the principal amount (or accreted value, if applicable) of such Permitted Refinancing Indebtedness does not exceed the principal amount (or accreted value, if applicable) of the Indebtedness or Disqualified Stock or Preferred Stock exchanged, renewed, refunded, refinanced, replaced, defeased or discharged (plus all accrued interest on the Indebtedness and all accrued dividends on the Disqualified Stock or Preferred Stock and the amount of all fees and expenses, including premiums, incurred in connection therewith);

(2) such Permitted Refinancing Indebtedness has a final maturity date that is (a) no earlier than the final maturity date of, and has a Weighted Average Life to Maturity equal to or greater than the Weighted Average Life to Maturity of, the Indebtedness or Disqualified Stock or Preferred Stock being exchanged, renewed, refunded, refinanced, replaced, defeased or discharged or (b) more than 90 days after the final maturity date of the notes;

(3) if the Indebtedness being exchanged, renewed, refunded, refinanced, replaced, defeased or discharged is subordinated in right of payment to the notes or the Note Guarantees, such Permitted Refinancing Indebtedness is subordinated in right of payment to the notes or the Note Guarantees, as applicable, on terms at least as favorable to the holders of notes as those contained in the documentation governing (or shall be Capital Stock of the obligor on) the Indebtedness being exchanged, renewed, refunded, refinanced, replaced, defeased or discharged, as determined in good faith by the Company;

(4) such Indebtedness is not incurred by a Restricted Subsidiary of the Company (other than a Guarantor) if the Company or a Guarantor is the issuer or other obligor on the Indebtedness being exchanged, renewed, refunded, refinanced, replaced, defeased or discharged;

(5) if any Preferred Stock being exchanged, renewed, refunded, refinanced, replaced, defeased or discharged was Disqualified Stock of the Company, the Permitted Refinancing Indebtedness shall be Disqualified Stock of the Company; and

(6) if any Preferred Stock being exchanged, renewed, refunded, refinanced, replaced, defeased or discharged was Preferred Stock of a Restricted Subsidiary, the Permitted Refinancing Indebtedness shall be Preferred Stock of such Restricted Subsidiary.

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Permitted Tax Distributions means, for any calendar year or portion thereof during which the Company (which, for purposes of this definition, shall mean MRD LLC, its accounting predecessor) was a pass-through entity for U.S. federal income tax purposes, any payments or distributions made by the Company to its members on or about each estimated tax payment date as well as each other applicable due date to enable the members of the Company (or, if any of them is itself a pass-through entity for U.S. federal income tax purposes, the owners of such member s Capital Stock) to make payments of U.S. federal and state income taxes (including estimates thereof) as a result of the operations of the Company and its Subsidiaries during the current or any previous calendar year, not to exceed an amount equal to each such member s (or in the case of a pass-through entity, the owners of its Capital Stock) U.S. federal and state income tax liability resulting solely from the pass-through tax treatment of such member s (or its owners) interest in the Company and as calculated pursuant to the terms of the limited liability company agreement of the Company as in effect on the date of the indenture, and as it may be amended, restated or otherwise modified from time to time; *provided* that such amendment, restatement or modification was not, considered as a whole, adverse in any material respect to the holders of the notes, as determined in the good faith by the Company.

Person means any individual, corporation, partnership, joint venture, association, joint-stock company, trust, unincorporated organization, limited liability company or government or other entity.

PIK Notes means the 10.00%/10.75% Senior PIK Toggle Notes due 2018 of the Company, as successor to MRD LLC.

Preferred Stock means, with respect to any Person, any and all preferred or preference stock or other similar Equity Interests (however designated) of such Person whether outstanding or issued after the date of the indenture.

Production Payments means Dollar-Denominated Production Payments and Volumetric Production Payments, collectively.

Production Payments and Reserve Sales means the grant or transfer by the Company or any of its Restricted Subsidiaries to any Person of a royalty, overriding royalty, net profits interest, Production Payment, partnership or other interest in Oil and Gas Properties, reserves or the right to receive all or a portion of the production or the proceeds from the sale of production attributable to such properties where the holder of such interest has recourse solely to such production or proceeds of production, subject to the obligation of the grantor or transferor to operate and maintain, or cause the subject interests to be operated and maintained, in a reasonably prudent manner or other customary standard or subject to the obligation of the grantor or transferor to indemnify for environmental, title or other matters customary in the Oil and Gas Business, including any such grants or transfers pursuant to incentive compensation programs on terms that are reasonably customary in the Oil and Gas Business for geologists, geophysicists or other providers of technical services to the Company or any of its Restricted Subsidiaries.

Reporting Default means a Default described in clause (5) under Events of Default and Remedies.

Restricted Investment means an Investment other than a Permitted Investment.

Restricted Subsidiary of a Person means any Subsidiary of the referent Person that is not an Unrestricted Subsidiary.

S&P means Standard & Poor s Ratings Services and any successor to the ratings business thereof.

SEC means the Securities and Exchange Commission.

Senior Debt means

(1) all Indebtedness of the Company or any of its Restricted Subsidiaries outstanding under Credit Facilities and all obligations under Hedging Obligations with respect thereto;

(2) any other Indebtedness of the Company or any of its Restricted Subsidiaries permitted to be incurred under the terms of the indenture, unless the instrument under which such Indebtedness is incurred expressly provides that it is subordinated in right of payment to the notes or any Note Guarantee; and

(3) all Obligations with respect to the items listed in the preceding clauses (1) and (2).

Notwithstanding anything to the contrary in the preceding sentence, Senior Debt will not include:

(1) any intercompany Indebtedness of the Company or any of its Restricted Subsidiaries to the Company or any of its Affiliates;

(2) any Indebtedness that is incurred in violation of the indenture; or

(3) any Capital Stock.

For the avoidance of doubt, Senior Debt will not include any Trade Payables or taxes owed or owing by the Company or any of its Restricted Subsidiaries.

Significant Subsidiary means any Restricted Subsidiary that would be a significant subsidiary as defined in Article 1, Rule 1-02 of Regulation S-X, promulgated pursuant to the Securities Act, as such Regulation is in effect on the date of the indenture.

Stated Maturity means, with respect to any installment of interest or principal on any series of Indebtedness, the date on which the payment of interest or principal was scheduled to be paid in the original documentation governing such Indebtedness, and will not include any contingent obligations to repay, redeem or repurchase any such interest or principal prior to the date originally scheduled for the payment thereof.

Subsidiary means, with respect to any specified Person:

(1) any corporation, association or other business entity (other than a partnership or limited liability company) of which more than 50% of the total voting power of its Voting Stock is at the time owned or controlled, directly or indirectly, by that Person or one or more of the other Subsidiaries of that Person (or a combination thereof); and

(2) any partnership or limited liability company of which (a) more than 50% of the capital accounts, distribution rights, total equity and voting interests or general or limited partnership interests, as applicable, are owned or controlled, directly or indirectly, by such Person or one or more of the other Subsidiaries of that Person or a combination thereof, whether in the form of membership, general, special or limited partnership interests or

otherwise, or (b) such Person or any Subsidiary of such Person is the sole or controlling general partner or manager or managing member of, or otherwise controls, such entity;

provided, *however*, that, notwithstanding the foregoing clauses (1) and (2), the MLP or any of its Subsidiaries shall be considered a Subsidiary of the Company only for so long as in the most recently available quarterly financial statements of the Company, the financial results of the MLP and its Subsidiaries are consolidated with the Company s financial results.

Trade Payables means, as to any Person, (a) accounts payable or other obligations of such Person created or assumed by such Person in the ordinary course of business in connection with the obtaining of goods or services and (b) obligations arising under contracts for the exploration, development, drilling, completion and plugging and abandonment of wells or for the construction, repair or maintenance of related infrastructure or facilities.

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Treasury Rate means, as of any redemption date, the yield to maturity as of such redemption date of the most recently issued United States Treasury securities with a constant maturity (as compiled and published in the most recent Federal Reserve Statistical Release H.15 (519) that has become publicly available at least two Business Days prior to the redemption date (or, if such Statistical Release is no longer published, any publicly available source of similar market data)) most nearly equal to the period from the redemption date to July 1, 2017; *provided*, *however*, that if the period from the redemption date to July 1, 2017, is less than one year, the weekly average yield on actually traded United States Treasury securities adjusted to a constant maturity of one year will be used. The Company will (a) calculate the Treasury Rate on the second Business Day preceding the applicable redemption date and (b) prior to such redemption date file with the trustee an officers certificate setting forth the Applicable Premium and the Treasury Rate and showing the calculation of each in reasonable detail.

Unrestricted Subsidiary means (i) if at such time in the most recently available quarterly financial statements of the Company, the financial results of MLP and its Subsidiaries are consolidated with the Company s financial results, the MLP and its Subsidiaries and (ii) any other Subsidiary of the Company (including any newly acquired or newly formed Subsidiary or a Person becoming a Subsidiary through merger or consolidation or Investment therein) that is designated (or deemed designated) by the Company s Board of Directors as an Unrestricted Subsidiary pursuant to a resolution of the Board of Directors, but only to the extent that such Subsidiary:

(1) has no Indebtedness other than Non-Recourse Debt owing to any Person other than the Company or any of its Restricted Subsidiaries (other than any Guarantee of the notes or the Note Guarantees or any Indebtedness that would be released upon such designation);

(2) except as permitted by the covenant described above under the caption Certain Covenants Transactions with Affiliates, is not party to any agreement, contract, arrangement or understanding with the Company or any Restricted Subsidiary of the Company unless the terms of any such agreement, contract, arrangement or understanding, together with the terms of all other agreements, contracts, arrangements and understandings with such Unrestricted Subsidiary, taken as a whole, are no less favorable to the Company or such Restricted Subsidiary than those that might be obtained at the time from Persons who are not Affiliates of the Company, as determined in good faith by the Company;

(3) is a Person with respect to which neither the Company nor any of its Restricted Subsidiaries has any direct or indirect obligation (a) to subscribe for additional Equity Interests or (b) to maintain or preserve such Person s financial condition or to cause such Person to achieve any specified levels of operating results; and

(4) has not Guaranteed or otherwise become an obligor on any Indebtedness of the Company or any of its Restricted Subsidiaries, except to the extent such Guarantee or obligation would be released upon such designation and except for (x) any Non-Recourse Debt with respect to which the Company or any Restricted Subsidiary has pledged (or provided a Guaranty limited in recourse solely to) Equity Interests in such Subsidiary or (y) any Guarantee of the notes and the Note Guarantees,

except, in the case of (1), (2), (3) or (4), for any such Indebtedness that is subject to a Guarantee by or other obligation of, or any agreement, contract, arrangement or understanding with, or any equity subscription or credit support obligation of, the Company or Restricted Subsidiary that constitutes an Investment in such Subsidiary that has been effected as a Restricted Payment or Permitted Investment that complies with the covenant described above under the caption Certain Covenants Restricted Payments.

All Subsidiaries of an Unrestricted Subsidiary shall also be Unrestricted Subsidiaries.

Volumetric Production Payments means production payment obligations recorded as deferred revenue in accordance with GAAP, together with all undertakings and obligations in connection therewith.

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Voting Stock of any specified Person as of any date means the Capital Stock of such Person entitling the holders thereof (whether at all times or only so long as no senior class of Capital Stock has voting power by reason of any contingency) to vote in the election of members of the Board of Directors of such Person; *provided* that with respect to a limited partnership or other entity which does not have a Board of Directors, Voting Stock means the Capital Stock of the general partner of such limited partnership or other business entity with the ultimate authority to manage the business and operations of such Person.

Weighted Average Life to Maturity means, when applied to any Indebtedness (or Disqualified Stock or Preferred Stock) at any date, the number of years obtained by dividing:

(1) the sum of the products obtained by multiplying (a) the amount of each then remaining installment, sinking fund, serial maturity or other required payments of principal or (with respect to Preferred Stock) redemption or similar payment, including payment at final maturity, in respect of the Indebtedness (or Disqualified Stock or Preferred Stock), by (b) the number of years (calculated to the nearest one-twelfth) that will elapse between such date and the making of such payment; by

(2) the then outstanding principal amount of such Indebtedness (or Disqualified Stock or Preferred Stock).

Wholly Owned Restricted Subsidiary means a Restricted Subsidiary all the Capital Stock of which (other than directors qualifying shares) is owned by the Company or another Wholly Owned Restricted Subsidiary.

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PLAN OF DISTRIBUTION

You may transfer new notes issued under the exchange offer in exchange for the old notes if:

- you acquire the new notes in the ordinary course of your business;
- you are not participating in, and do not intend to participate in, and have no arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of such new notes in violation of the provisions of the Securities Act; and
- you are not our affiliate (within the meaning of Rule 405 under the Securities Act).

Each broker-dealer that receives new notes for its own account pursuant to the exchange offer in exchange for old notes that were acquired by such broker-dealer as a result of market-making or other trading activities 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 as a result of market-making activities or other trading activities.

If you wish to exchange new notes for your old notes in the exchange offer, you will be required to make representations to us as described in Exchange Offer Purpose and Effect of the Exchange Offer and Exchange Offer Procedures for Tendering Your Representations to Us in this prospectus and in the letter of transmittal. In addition, if you are a broker-dealer who receives new notes for your own account in exchange for old notes that were acquired by you as a result of market-making activities or other trading activities, you will be required to acknowledge that you will deliver a prospectus in connection with any resale by you of such new notes.

We will not receive any proceeds from any sale of new notes by broker-dealers. New notes received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions in any of the following ways:

- in the over-the-counter market;
- in negotiated transactions;
- through the writing of options on the new notes or a combination of such methods of resale;
- at market prices prevailing at the time of resale;
- at prices related to such prevailing market prices; or

at negotiated prices.

Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such new notes.

Any broker-dealer that resells new notes that were received by it for its own account pursuant to the exchange offer in exchange for old notes that were acquired by such broker-dealer as a result of market-making or other trading activities may be deemed to be an underwriter within the meaning of the Securities Act. The letter of transmittal states that by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act. We agreed to permit the use of this prospectus 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. Furthermore, we agree to amend or supplement this prospectus during such period, if so requested, in order to expedite or facilitate the disposition of any new notes by broker-dealers.

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We have agreed to pay all expenses incident to the exchange offer other than fees and expenses of counsel to the holders and brokerage commissions and transfer taxes, if any, and will indemnify the holders of the old notes (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS

The following discussion is a summary of certain U.S. federal income tax considerations relevant to the exchange of old notes for new notes, but does not purport to be a complete analysis of all potential tax effects. The discussion is based upon the Internal Revenue Code of 1986, as amended, or the Code, Treasury Regulations, Internal Revenue Service rulings and pronouncements and judicial decisions now in effect, all of which may be subject to change at any time by legislative, judicial or administrative action. These changes may be applied retroactively in a manner that could adversely affect a holder of new notes. We cannot assure you that the Internal Revenue Service will not challenge one or more of the tax consequences described in this discussion, and we have not obtained, nor do we intend to obtain, a ruling from the Internal Revenue Service or an opinion of counsel with respect to the U.S. federal income tax consequences described herein. Some holders, including financial institutions, insurance companies, regulated investment companies, tax-exempt organizations, dealers in securities or currencies, persons whose functional currency is not the U.S. dollar or persons who hold the notes as part of a hedge, conversion transaction, straddle or other risk reduction transaction may be subject to special rules not discussed below.

We recommend that each holder consult its own tax advisor as to the particular tax consequences of exchanging such holder s old notes for new notes, including the applicability and effect of any foreign, state, local or other tax laws or U.S. federal estate or gift tax considerations.

We believe that the exchange of old notes for new notes will not be an exchange or otherwise a taxable event to a holder for U.S. federal income tax purposes. Accordingly, a holder will not recognize gain or loss upon receipt of a new note in exchange for an old note in the exchange, and the holder s basis and holding period in the new note will be the same as its basis and holding period in the corresponding old note immediately before the exchange.

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LEGAL MATTERS

The validity of the new notes offered in this exchange offer will be passed upon for us by Akin Gump Strauss Hauer & Feld LLP, Houston, Texas.

EXPERTS

The consolidated and combined balance sheets of Memorial Resource Development Corp. as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations, equity, and cash flows for each of the years in the three-year period ended December 31, 2014, have been included herein in reliance upon the reports of KPMG LLP, independent registered public accounting firm, appearing elsewhere herein, and upon the authority of said firm as experts in accounting and auditing.

The audit report covering the December 31, 2014 consolidated and combined financial statements contains an explanatory paragraph that states that as discussed in Note 1 to the consolidated and combined financial statements, the Company s balance sheets and related statements of operations, equity, and cash flows have been prepared on a combined basis of accounting.

The statements of revenues and direct operating expenses related to the properties acquired in the MEMP Wyoming Acquisition for each of the years in the three-year period ended December 31, 2013, have been included herein in reliance upon the reports of KPMG LLP, independent auditor, appearing elsewhere herein, and upon the authority of said firm as experts in accounting and auditing.

Estimated quantities of the proved oil and natural gas reserves and the net present value of such reserves as of December 31, 2014 set forth in this prospectus are based on reserve reports prepared by our management and audited by Netherland, Sewell & Associates, Inc. Our acreage had been audited or evaluated by an independent reservoir engineering firm since 2011 and Netherland, Sewell & Associates, Inc. audited these reserves as of December 31, 2014. Our estimate of probable and possible reserves are prepared by management and audited by Netherland, Sewell & Associates, Inc.

Estimated quantities of certain MEMP proved oil and natural gas reserves and the net present value of such reserves as of December 31, 2014 set forth in this prospectus are based on the reserve report prepared by our management and audited by Netherland, Sewell & Associates, Inc. MEMP s acreage had been audited or evaluated by an independent reservoir engineering firm since 2011 and Netherland, Sewell & Associates, Inc. audited these reserves as of December 31, 2014.

We have included these estimates in reliance on the authority of Netherland, Sewell & Associates, Inc. as experts in such matters.

Estimated quantities of certain MEMP proved oil and natural gas reserves as of December 31, 2014 set forth in this prospectus are based on a reserve report prepared by our internal reserve engineers and audited by Ryder Scott Company, L.P. These estimates are so included in reliance upon the authority of such firm as an expert in these matters.

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WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-4 under the Securities Act with respect to the issuance of the new notes. This prospectus, which is included in the registration statement, does not contain all of the information included in the registration statement. Certain parts of this registration statement are omitted in accordance with the rules and regulations of the SEC. For further information about us and the new notes, we refer you to the registration statement. You should be aware that the statements made in this prospectus as to the contents of any agreement or other document filed as an exhibit to the registration statement are not complete. Although we believe that we have summarized the material terms of these documents in the prospectus, these statements should be read along with the full and complete text of the related documents.

This prospectus contains summaries and other information that we believe are accurate as of the date hereof with respect to specific terms of specific documents, but we refer to the actual documents for complete information with respect to those documents. Statements contained in this prospectus as to the contents of any contract or other document referred to in this prospectus do not purport to be complete. Where reference is made to the particular provisions of a contract or other document, the provisions are qualified in all respects by reference to all of the provisions of the contract or other document. Industry and company data are approximate and reflect rounding in certain cases.

We are subject to the informational requirements of the Exchange Act and accordingly file reports and other information with the SEC. These reports and other information may be inspected and copied at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information regarding the public reference room. In addition, our filings with the SEC are also available to the public on the SEC s website at http://www.sec.gov.

Our website is located at http://www.memorialrd.com, and we make our periodic reports and other information filed with or furnished to the SEC available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus. You may also request a copy of these filings at no cost, by writing or telephoning us at the following address: 500 Dallas Street, Suite 1800, Houston, Texas 77002, (713) 588-8300.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

Introduction

Memorial Resource Development Corp. (the Company) is a Delaware corporation engaged in the acquisition, exploration, and development of natural gas and oil properties primarily in North Louisiana. The Company controls Memorial Production Partners LP (MEMP) through the ownership of Memorial Production Partners GP LLC (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, the Company is required to consolidate MEMP for accounting and financial reporting purposes.

On July 1, 2014, MEMP consummated its acquisition of oil and natural gas liquids properties in Wyoming from Merit Energy Company, LLC and certain of its affiliates (the Wyoming Acquisition). The unaudited pro forma condensed combined statement of operations for the year ended December 31, 2014 is based on the audited statement of operations of the Company for the year ended December 31, 2014 and the unaudited statement of revenues and direct operating expenses of the Wyoming Acquisition for the six months ended June 30, 2014, and includes pro forma adjustments to give effect to the Wyoming Acquisition as if the transaction occurred on January 1, 2014.

The pro forma adjustments to the historical combined financial statements are based on currently available information and certain estimates and assumptions. The actual effect of the transactions discussed in the accompanying notes ultimately may differ from the unaudited pro forma adjustments included herein. However, management believes that the assumptions utilized to prepare the pro forma adjustments provide a reasonable basis for presenting the significant effects of the transactions and that the unaudited pro forma adjustments are factually supportable, give appropriate effect to the impact of events that are directly attributable to the transactions, and reflect those items expected to have a continuing impact on the Partnership.

The unaudited pro forma combined statement of operations should be read in conjunction with the notes thereto and with our historical financial statements and the historical financial statements of the Wyoming Acquisition, included elsewhere in this prospectus.

The Company s unaudited pro forma condensed combined statement of operations is not necessarily indicative of the results that actually would have occurred if MEMP had completed the Wyoming Acquisition or the related financing transactions on the dates indicated or which could be achieved in the future because they necessarily exclude various operating expenses.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2014

(in thousands, except per share amounts)

	For the Year Ended December 31, 2014	For the Six Months Ended June 30, 2014		
	Company Historical	Wyoming Acquisition Historical	Pro Forma Adjustments	Company Pro Forma Combined
Revenues:				
Oil & natural gas sales	$ 894,967	$ 91,199	$	$ 986,166
Pipeline tariff income and other	4,378			4,378
Total revenues	899,345	91,199		990,544
Costs and expenses:				
Lease operating	161,303	24,608		185,911
Pipeline operating	2,068			2,068
Exploration	16,603			16,603
Production and ad valorem taxes	45,751	11,943		57,694
Depreciation, depletion, and amortization	314,193		29,383(a)	343,576
Impairment of proved oil and natural gas properties	432,116			432,116
Incentive unit compensation expense	943,949			943,949
General and administrative	87,673			87,673
Accretion of asset retirement obligations	6,306		163(a)	6,469
(Gain) loss on commodity derivative instruments	(749,988)			(749,988)
Other, net	(12)			(12)
Total costs and expenses	1,263,019	36,551	29,546	1,329,116
Operating income	(363,674)	54,648	(29,546)	(358,572)
Other income (expense):				
Interest expense, net	(133,833)		(11,319)(b)	(145,152)
			(222)(c)	(222)
Loss on extinguishment of debt	(37,248)			(37,248)
Other, net	(337)			(337)

Total other income (expense)	(171,418)		(11,541)	(182,959)
Income (loss) before income taxes	(535,092)	54,648	(41,087)	(521,531)
Income tax benefit (expense)	(100,971)			(100,971)
Net income (loss)	$ (636,063)	$ 54,648	$ (41,087)	$ (581,415)
Historical and pro forma net income (loss) available to common stockholders:				
Net income (loss) available to common stockholders	$ (784,581)			$ (784,581)
Earnings per unit:				
Basic and diluted earnings per unit	$ (4.08)			$ (4.08)
Weighted average common and common equivalent shares outstanding:				
Basic and diluted	192,498			192,498

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS

Note 1. Basis of Presentation

Memorial Resource Development Corp. (the Company) is a Delaware corporation engaged in the acquisition, exploration, and development of natural gas and oil properties primarily in North Louisiana. The Company controls Memorial Production Partners LP (MEMP) through the ownership of Memorial Production Partners GP LLC (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, the Company is required to consolidate MEMP for accounting and financial reporting purposes.

On July 1, 2014, MEMP consummated its acquisition of oil and natural gas liquids properties in Wyoming from Merit Energy Company, LLC and certain of its affiliates (the Wyoming Acquisition). MEMP funded the Wyoming Acquisition through borrowings under its revolving credit facility. The unaudited pro forma condensed combined statement of operations for the year ended December 31, 2014 is based on the audited statement of operations of the Company for the year ended December 31, 2014 and the unaudited statement of revenues and direct operating expenses of the Wyoming Acquisition for the six months ended June 30, 2014, and includes pro forma adjustments to give effect to the Wyoming Acquisition as if the transaction occurred on January 1, 2014.

The Company believes that the assumptions used in the preparation of these unaudited pro forma condensed combined statement of operations for the year ended December 31, 2014 provide a reasonable basis for presenting the effects directly attributable to the transactions described above.

The unaudited pro forma combined statement of operations and the notes thereto should be read in conjunction with the Company s historical financial statements and the historical financial statements of the Wyoming Acquisition, included elsewhere in this prospectus.

Note 2. Pro Forma Adjustments and Assumptions

Unaudited Pro Forma Condensed Combined Statement of Operations

The following adjustments were made in the preparation of the unaudited pro forma condensed combined statement of operations for the year ended December 31, 2014:

(a) Pro forma adjustment to reflect the depletion and depreciation on property and equipment and the accretion expense on asset retirement obligations associated with the Wyoming Acquisition.

(b) Pro forma adjustment to reflect the incurrence of interest expense on $838.5 million of additional borrowings under MEMP s revolving credit facility used to fund the Wyoming Acquisition. Pro forma interest expense was based on a rate of 2.70%. A one-eighth percentage point change in the interest rate would change pro forma interest associated with these additional borrowings by $0.5 million.

(c) Pro forma adjustment to reflect the amortization of $2.3 million of deferred financing costs as if the borrowing costs associated with the Wyoming Acquisition were incurred on January 1, 2014.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Memorial Resource Development Corp.:

We have audited the accompanying consolidated and combined balance sheets of Memorial Resource Development Corp. and subsidiaries (the Company) as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations, equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated and combined financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of Memorial Resource Development Corp. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated and combined financial statements, the balance sheets, and the related statements of operations, equity, and cash flows have been prepared on a combined basis of accounting.

/s/ KPMG LLP

Dallas, Texas

March 18, 2015

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MEMORIAL RESOURCE DEVELOPMENT CORP.

CONSOLIDATED AND COMBINED BALANCE SHEETS

(In thousands, except outstanding shares)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,958	$ 77,721
Restricted cash		35,000
Accounts receivable:		
Oil and natural gas sales	82,263	68,764
Joint interest owners and other	49,313	19,958
Affiliates		4,652
Short-term derivative instruments	340,056	9,289
Prepaid expenses and other current assets	28,027	19,513
Total current assets	505,617	234,897
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	4,844,529	3,037,298
Other	33,815	10,331
Accumulated depreciation, depletion and impairment	(1,340,688)	(627,925)
Property and equipment, net	3,537,656	2,419,704
Long-term derivative instruments	435,369	48,616
Restricted investments	77,361	73,385
Restricted cash	260	15,506
Other long-term assets	37,284	37,053
Total assets	$ 4,593,547	$ 2,829,161
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 25,772	$ 20,734
Accounts payable affiliates	624	1,975
Revenues payable	57,352	56,091
Accrued liabilities	199,000	98,130
Short-term derivative instruments	3,289	9,711
Total current liabilities	286,037	186,641
Long-term debt MRD Segment	783,000	871,150
Long-term debt MEMP Segment	1,595,413	792,067
Asset retirement obligations	122,531	111,679
Long-term derivative instruments		6,080

Deferred tax liabilities	95,017	3,106
Other long-term liabilities	8,585	306
Total liabilities	2,890,583	1,971,029
Commitments and contingencies (Note 16)		
Equity:		
Stockholders equity (deficit):		
Preferred stock, $.01 par value: 50,000,000 shares authorized; no shares issued and outstanding		
Common stock, $.01 par value: 600,000,000 shares authorized; 193,435,414 shares issued and outstanding at December 31, 2014; no shares authorized, issued or outstanding at December 31, 2013	1,935	
Additional paid-in capital	1,367,346	
Accumulated earnings (deficit)	(786,871)	
Total stockholders equity	582,410	
Members equity:		
Members		237,186
Previous owners (Note 1)		40,331
Total members equity		277,517
Noncontrolling interests	1,120,554	580,615
Total equity	1,702,964	858,132
Total liabilities and equity	$ 4,593,547	$ 2,829,161

See Accompanying Notes to Consolidated and Combined Financial Statements.

MEMORIAL RESOURCE DEVELOPMENT CORP.

STATEMENTS OF CONSOLIDATED AND COMBINED OPERATIONS

(In thousands, except per share amounts)

	For Year Ended December 31, 2014	2013	2012
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: (Note 10)			
Basic	$ (4.08)	$	$
Diluted	$ (4.08)	$	$
Weighted average common and common equivalent shares outstanding:			
Basic	192,498		
Diluted	192,498		

See Accompanying Notes to Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

STATEMENTS OF CONSOLIDATED AND COMBINED CASH FLOWS

(In thousands)

	For Year Ended December 31, 2014	2013	2012
Cash flows from operating activities:			
Net income (loss)	$ (636,063)	$ 151,332	$ 26,997
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	314,193	184,717	138,672
Impairment of proved oil and natural gas properties	432,116	6,600	28,871
(Gain) loss on derivatives	(749,843)	(29,533)	(29,323)
Cash settlements (paid) received on derivative instruments	20,559	30,403	72,045
Cash settlements on terminated derivatives	5,326		
Premiums paid for derivatives	(6,065)		(411)
Loss on extinguishment of debt	30,248		
Amortization of deferred financing costs	7,436	8,343	3,584
Accretion of senior notes net discount	2,501	554	
Amortization of investment premium			194
Accretion of asset retirement obligations	6,306	5,581	5,009
Amortization of equity awards	10,678	3,557	1,423
(Gain) loss on sale of properties	3,057	(85,621)	(9,761)
Non-cash compensation expense	916,218	1,057	
Exploration costs	14,953	181	6,980
Deferred income tax expense (benefit)	100,230	76	(312)
Changes in operating assets and liabilities:			
Accounts receivable	(17,635)	(15,758)	(7,382)
Prepaid expenses and other assets	(7,424)	(2,986)	(1,574)
Payables and accrued liabilities	21,208	19,320	5,392
Other	8,272		
Net cash provided by operating activities	476,271	277,823	240,404
Cash flows from investing activities:			
Acquisitions of oil and natural gas properties	(1,177,670)	(105,762)	(360,678)
Additions to oil and gas properties	(674,396)	(360,015)	(273,334)
Additions to other property and equipment	(17,067)	(2,670)	(2,674)
Additions to restricted investments	(3,976)	(5,361)	(4,599)
Deposits for property acquisitions	(215)		
Decrease (increase) in restricted cash	49,946	(49,347)	(3)
Proceeds from the sale of oil and natural gas properties	6,700	155,712	34,521
Other	(301)		29
Net cash used in investing activities	(1,816,979)	(367,443)	(606,738)

Cash flows from financing activities:			
Advances on revolving credit facilities	2,746,800	1,132,755	619,450
Payments on revolving credit facilities	(2,457,900)	(1,766,037)	(251,569)
Proceeds from the issuances of senior notes	1,092,425	1,031,563	
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	(30,334)	(41,175)	(3,501)
Proceeds from initial public offering	408,500		
Costs incurred in conjunction with initial public offering	(28,373)		
Proceeds from MEMP public offering	553,288	511,204	202,573
Costs incurred in conjunction with MEMP public offering	(12,510)	(21,066)	(8,268)
Proceeds from changes in ownership interests in MEMP		135,012	
Repurchased shares under repurchase program	(161)		
Repurchases under MEMP unit repurchase program	(11,531)		
Restricted MEMP units returned to plan	(1,012)		
Purchase of additional interests in consolidated subsidiaries	(3,292)	(15,135)	
Contributions from previous owners		1,214	44,072
Contributions from NGP affiliates related to sale of properties	1,165	2,013	45,158
Distributions to the Funds		(732,362)	
Distributions to MRD Holdco	(59,803)		
Distributions to noncontrolling interests	(149,084)	(78,083)	(15,208)
Distribution to NGP affiliates related to purchase of assets	(66,693)	(355,494)	(242,174)
Distribution to NGP affiliates related to sale of assets, net of cash received	(32,770)		
Distributions made by previous owners		(4,005)	(28,772)
Cash retained by previous owners		(7,909)	
Other	320	455	
Net cash provided by financing activities	1,268,945	117,950	361,761
Net change in cash and cash equivalents	(71,763)	28,330	(4,573)
Cash and cash equivalents, beginning of period	77,721	49,391	53,964
Cash and cash equivalents, end of period	$ 5,958	$ 77,721	$ 49,391

See Accompanying Notes to Consolidated and Combined Financial Statements.

See Supplemental cash flow information (Note 2)

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MEMORIAL RESOURCE DEVELOPMENT CORP.

STATEMENTS OF CONSOLIDATED AND COMBINED EQUITY

(In thousands)

	Members	Members Equity Previous Owners	Noncontrolling Interest	Total
Balance, December 31, 2011	$ 853,436	$ 261,340	$ 161,588	$ 1,276,364
Net income (loss)	(7,620)	37,318	(2,701)	26,997
Contributions		44,072		44,072
Contribution of oil and gas properties from NGP affiliate		6,893		6,893
Net proceeds from MEMP public equity Offering			194,134	194,134
Distributions		(28,772)	(15,255)	(44,027)
Net book value of net assets acquired from affiliates	52,217	(93,696)	41,479	
Amortization of MEMP equity awards			1,423	1,423
Noncontrolling interest s share of net book value in excess of consideration received from sale of assets to MEMP	727		(727)	
Contribution related to sale of assets to NGP affiliate	6,291	40,138	742	47,171
Net book value of assets acquired by NGP affiliate	(579)	(33,859)	(68)	(34,506)
Distribution to affiliate in connection with acquisition of assets	(134,964)		(107,210)	(242,174)
Impact from equity transactions of MEMP	41,930		(41,930)	
Other	176	(1)	187	362
Balance, December 31, 2012	811,614	233,433	231,662	1,276,709
Net income (loss)	90,712	10,790	49,830	151,332
Contributions		1,214		1,214
Net Proceeds from MEMP public equity offering			490,138	490,138
Sale of MEMP common units	60,701		74,311	135,012
Distributions	(732,362)	(4,005)	(78,083)	(814,450)
Net book value of net assets acquired from affiliates	50,751	(181,556)	130,805	
Amortization of MEMP equity awards			3,558	3,558
Noncontrolling interest s share of cash consideration received in excess of the net book value sold to MEMP	(24)		24	
Distribution to affiliate in connection with acquisition of assets	(98,180)		(253,055)	(351,235)
Purchase of noncontrolling interests	(303)		(14,832)	(15,135)
Impact of equity transactions of MEMP	54,183		(54,183)	
Other	94	(2,299)	440	(1,765)
Net assets retained by previous owners		(17,246)		(17,246)

Balance, December 31, 2013	$ 237,186	$ 40,331	$ 580,615	$ 858,132

Continued

See Accompanying Notes to Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

STATEMENTS OF CONSOLIDATED AND COMBINED EQUITY CONTINUED

(In thousands)

	Stockholders Equity			Members Equity			
	Common stock	Additional paid in capital	Accumulated earnings (deficit)	Members	Previous Owners	Noncontrolling Interest	Total
Balance, December 31, 2013	$	$	$	$ 237,186	$ 40,331	$ 580,615	$ 858,132
Net income (loss)			(784,581)	20,305	1,425	126,788	(636,063)
Issuance of shares in connection with restructuring transactions (Note 1)	1,710	913,152					914,862
Issuance of shares in connection with initial public offering (Note 1)	215	379,962					380,177
Tax related effects in connection with restructuring transactions and initial public offering		(43,251)					(43,251)
Share repurchase	(1)		(2,214)				(2,215)
Restricted stock awards	11	(11)					
Amortization of restricted stock awards		2,804					2,804
Contribution related to MRD Holdco incentive unit compensation expense (Note 12)		111,866					111,866
Purchase of noncontrolling interests		(2,881)				(411)	(3,292)
Contribution related to sale of assets to NGP affiliate				1,165			1,165
Net book value of assets sold to NGP affiliate				(621)			(621)
				45,059	(41,756)		3,303

Net book value of assets acquired from NGP affiliates							
Distribution to NGP affiliates in connection with acquisition of assets				(66,693)			(66,693)
Distribution of net assets to MRD Holdco				(123,078)		29,994	(93,084)
Distribution of shares received in connection with restructuring transactions to MRD Holdco				(110,510)			(110,510)
Net equity deemed contribution (distribution) related to net assets transferred to MEMP		5,327		(2,659)		(2,668)	
Net proceeds from MEMP public equity offering						540,698	540,698
Distributions						(149,084)	(149,084)
Amortization of MEMP equity awards						7,874	7,874
MEMP common units repurchased						(12,903)	(12,903)
MEMP restricted units repurchased						(1,012)	(1,012)
Other		378	(76)	(154)		663	811
Balance, December 31, 2014	$ 1,935	$ 1,367,346	$ (786,871)	$	$	$ 1,120,554	$ 1,702,964

See Accompanying Notes to Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Note 1. Organization and Basis of Presentation

Overview

Memorial Resource Development Corp. (the Company) is a publicly traded Delaware corporation, the common shares of which are listed on the NASDAQ Global Market (NASDAQ) under the symbol MRD. Unless the context requires otherwise, references to we, us, our, MRD, or the Company are intended to mean the business and operations of Memorial Resource Development Corp. and its consolidated subsidiaries.

The Company was formed by Memorial Resource Development LLC (MRD LLC) in January 2014 to acquire, explore and develop natural gas and oil properties in North America. MRD LLC 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 explore, develop and acquire natural gas and oil properties. The Funds are private equity funds managed by Natural Gas Partners (NGP). MRD LLC s consolidated and combined financial statements represent our predecessor for accounting and financial reporting purposes prior to our initial public offering.

Initial Public Offering and Restructuring Transactions

On June 18, 2014, the Company completed its initial public offering of 21,500,000 common units at a price of $19.00 per share, which generated net proceeds to the Company of approximately $380.2 million after deducting underwriting discounts and commissions and other offering related fees and expenses. The following restructuring events and transactions occurred in connection with our initial public offering:

- The Funds contributed all of their interests in MRD LLC to MRD Holdco LLC (MRD Holdco) and the members of our management who owned incentive units in MRD LLC exchanged those incentive units for substantially identical incentive units in MRD Holdco, after which MRD Holdco owned 100% of MRD LLC;

- WildHorse Resources, LLC (WildHorse Resources) sold its subsidiary, WildHorse Resources Management Company, LLC (WHR Management Company), to an affiliate of the Funds for approximately $0.2 million in cash, and WHR Management Company entered into a services agreement with the Company and WildHorse Resources pursuant to which WHR Management Company agreed to provide certain management services to WildHorse Resources, which was terminated as of March 1, 2015;

- Classic Hydrocarbons Holdings, L.P. (Classic) and Classic Hydrocarbons GP Co., L.L.C. (Classic GP) distributed to MRD LLC the ownership interests in Classic Pipeline & Gathering, LLC (Classic Pipeline), which owns certain midstream assets in Texas, and Black Diamond Minerals, LLC (Black Diamond) distributed to MRD LLC its ownership interests in Golden Energy Partners LLC (Golden Energy), which sold all of its assets in May 2014;

MRD LLC contributed to us substantially all of its assets, comprised of: (i) 100% of the ownership interests in Classic, Classic GP, Black Diamond, Beta Operating Company, LLC (Beta Operating), Memorial Resource Finance Corp., MRD Operating LLC (MRD Operating), Memorial Production Partners GP LLC (MEMP GP) (including MEMP GP s ownership of 50% of Memorial Production Partners LP s (MEMP) incentive distribution rights) and (ii) 99.9% of the membership interests in WildHorse Resources;

We issued 128,665,677 shares of our common stock to MRD LLC, which MRD LLC immediately distributed to MRD Holdco;

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We assumed the obligations of MRD LLC under the indenture governing the $350 million in aggregate principal amount of 10.00% / 10.75% Senior PIK Toggle Notes due 2018 (the PIK notes) and reimbursed MRD LLC for the June 15, 2014 interest payment made on the PIK notes;

Certain former management members of WildHorse Resources contributed to us their outstanding incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources, and we issued 42,334,323 shares of our common stock and paid cash consideration of $30.0 million to such former management members of WildHorse Resources;

We entered into a registration rights agreement and a voting agreement with MRD Holdco and certain former management members of WildHorse Resources;

We entered into a new $2.0 billion revolving credit facility (see Note 8) and used approximately $614.5 million in borrowings under that facility to repay all amounts outstanding under WildHorse Resources credit agreements, to partially fund the cash consideration payable to the former management members of WildHorse Resources and to reimburse MRD LLC for the June 15, 2014 interest payment made on the PIK notes;

Notice of redemption was given to the PIK notes trustee (see Note 8) specifying a redemption date of July 16, 2014 and indicating that a portion of the net proceeds from our initial public offering, which temporarily reduced amounts outstanding under our new revolving credit facility, would be used to redeem the PIK notes at a redemption price of 102% of the principal amount of the PIK notes plus accrued and unpaid interest thereon to the date of redemption;

MRD Operating entered into a merger agreement with MRD LLC pursuant to which after the termination or earlier discharge of the PIK notes MRD LLC would merge into MRD Operating;

MRD LLC distributed to MRD Holdco the following: (i) BlueStone Natural Resources Holdings, LLC (BlueStone), which sold substantially all of its assets in July 2013 for $117.9 million, MRD Royalty LLC, which owns certain leasehold interests and overriding royalty interests in Texas and Montana, MRD Midstream LLC, which owns an indirect interest in certain midstream assets in North Louisiana, Golden Energy and Classic Pipeline; (ii) 5,360,912 subordinated units of MEMP; (iii) the right to the remaining cash to be released from the debt service reserve account in connection with the redemption or earlier discharge of the PIK notes plus the cash received from us in reimbursement of the interest paid on June 15, 2014 in respect of 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 irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee; and

MRD LLC merged into MRD Operating.

Previous Owners

References to the previous owners for accounting and financial reporting purposes refer collectively to:

Certain oil and natural gas properties and related assets primarily in the Permian Basin, East Texas and the Rockies that MEMP acquired through equity transactions in October 2013 from certain affiliates of NGP. In October 2013, MEMP acquired Boaz Energy, LLC (Boaz), Crown Energy Partners, LLC (Crown), the Crown net profits interest and overriding royalty interest (Crown NPI/ORRI), Propel Energy SPV LLC (Propel SPV), together with its wholly-owned subsidiary Propel Energy Services, LLC (Propel Energy Services), and Stanolind Oil and Gas SPV LLC (Stanolind SPV) from

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Boaz Energy Partners, LLC (Boaz Energy Partners), Crown Energy Partners Holdings, LLC (Crown Holdings), Propel Energy, LLC (Propel Energy) and Stanolind Oil and Gas LP (Stanolind), all of which are primarily owned by two of the Funds.

A net profits interest that WildHorse Resources purchased from NGP Income Co-Investment Fund II, L.P. (NGPCIF) in February 2014 (NGPCIF NPI). NGPCIF is controlled by NGP. Upon the completion of the 2010 Petrohawk and Clayton Williams acquisitions, WildHorse Resources sold a net profits interest in these properties to NGPCIF. Since WildHorse Resources sold the net profits interest, the historical results are accounted for as a working interest for all periods.

Our audited financial statements reported herein include the financial position and results attributable to: (i) those certain oil and natural gas properties and related assets that MEMP acquired through equity transactions in October 2013 from Boaz Energy Partners, Crown Holdings, Propel Energy and Stanolind and (ii) NGPCIF NPI.

Basis of Presentation

The financial statements reported herein include the financial position and results attributable to both 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 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.

All material intercompany transactions and balances have been eliminated in preparation of our consolidated and combined financial statements. The accompanying consolidated and combined financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP).

We have two reportable business segments, both of which are engaged in the acquisition, exploration, development and production of oil and natural gas properties (See Note 14). 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 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 for comparability purposes:

acquisition by MEMP of all the outstanding membership interests in Tanos Energy, LLC (Tanos) from MRD LLC for a purchase price of approximately $77.4 million on October 1, 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 on October 1, 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 on October 1, 2013;

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acquisition by MEMP of all the outstanding membership interests in WHT Energy Partners LLC (WHT) from WildHorse Resources and Tanos for a purchase price of approximately $200.0 million on March 28, 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.

Note 2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of consolidated and combined financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated and combined financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Significant estimates include, but are not limited to, oil and natural gas reserves; depreciation, depletion, and amortization of proved oil and natural gas properties; future cash flows from oil and natural gas properties; impairment of long-lived assets; fair value of derivatives; fair value of equity and incentive unit compensation; fair values of assets acquired and liabilities assumed in business combinations and asset retirement obligations.

Principles of Consolidation and Combination

Our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. Likewise, the combined financial statements include the accounts of our predecessor and the previous owners as discussed above. All material intercompany balances and transactions have been eliminated. Certain prior period balances have been reclassified to better align with financial statement presentation in the current fiscal year.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and all highly liquid investments with original contractual maturities of three months or less.

Book Overdrafts

Book overdrafts, representing outstanding checks in excess of funds on deposit, are classified as accounts payable and the change in the related balance is reflected in operating activities in the statement of cash flows.

Concentrations of Credit Risk

Cash balances, accounts receivable, restricted investments and derivative financial instruments are financial instruments potentially subject to credit risk. Cash and cash equivalents are maintained in bank deposit accounts which, at times, may exceed the federally insured limits. Management periodically reviews and assesses the financial condition of the banks to mitigate the risk of loss. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds

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associated with MEMP s offshore Southern California oil and gas properties. These restricted investments may consist of money market deposit accounts, money market mutual funds, commercial paper, and U.S. Government securities, all held with credit-worthy financial institutions. Derivative financial instruments are generally executed with major financial institutions that expose us to market and credit risks and which may, at times, be concentrated with certain counterparties. The credit worthiness of the counterparties is subject to continual review. We rely upon netting arrangements with counterparties to reduce credit exposure. Neither we nor our predecessor and the previous owners have experienced any losses from such instruments.

Oil and natural gas are sold to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Accounts receivable from joint operations are from a number of oil and natural gas companies, partnerships, individuals, and others who own interests in the properties operated by us, our predecessor, and the previous owners. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells, minimizing the credit risk associated with these receivables. Additionally, management believes that any credit risk imposed by a concentration in the oil and natural gas industry is mitigated by the creditworthiness of its customer base. An allowance for doubtful accounts is recorded after all reasonable efforts have been exhausted to collect or settle the amount owed. Any amounts outstanding longer than the contractual terms are considered past due. Management determined that an allowance for uncollectible accounts was unnecessary at both December 31, 2014 and 2013, respectively.

If we were to lose any one of our customers, the loss could temporarily delay the production and the sale of oil and natural gas in the related producing region. If we were to lose any single customer, we believe that a substitute customer to purchase the impacted production volumes could be identified.

Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. 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 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 oil and gas reserves related to the associated field. Capitalized drilling and development costs of producing oil and natural gas 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 removed from the property accounts, and any gain or loss is recognized.

There were no material capitalized exploratory drilling costs pending evaluation at December 31, 2014, 2013 and 2012.

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Oil and Gas Reserves

The estimates of proved oil and natural gas 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 Financial Accounting Standards Board (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. Netherland, Sewell & Associates, Inc. (NSAI), our independent reserve engineers, was engaged to audit our internally prepared reserves estimates at December 31, 2014. MEMP engaged NSAI and Ryder Scott Company, L.P. to audit MEMP s internally prepared reserves estimates for all of MEMP s proved reserves (by volume) at December 31, 2014.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. 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 oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Other Property & Equipment

Other property and equipment is stated at historical cost and is comprised primarily of vehicles, furniture, fixtures, office build-out cost and computer hardware and software. Depreciation of other property and equipment is calculated using the straight-line method generally based on estimated useful lives of three to seven years.

Asset Retirement Obligations

An asset retirement obligation associated with retiring long-lived assets is recognized as a liability on a discounted basis in the period in which the legal obligation is incurred and becomes determinable, with an equal amount capitalized as an addition to oil and natural gas properties, which is allocated to expense over the useful life of the asset. Generally, oil and gas producing companies incur such a liability upon acquiring or drilling a well. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. Upon settlement of the liability, a gain or loss is recognized in net income (loss) to the extent the actual costs differ from the recorded liability. See Note 6 for further discussion of asset retirement obligations.

Impairments

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. This may be due to 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. Impairment expense for the years ended December 31, 2014, 2013, and 2012 was approximately $432.1 million, $6.6 million, $28.9 million, respectively. See Note 4 for further discussion on impairments.

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Restricted Investments

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. These investments are classified as held-to-maturity, and such investments are stated at amortized cost. Interest earned on these investments is included in interest expense net in the statement of operations. The amortized cost of such investments is adjusted for amortization of premiums and accretion of discounts to maturity. Such amortization and accretion is displayed as a separate line item in the statement of operations. These restricted investments consist of money market deposit accounts, money market mutual funds, commercial paper, and U.S. Government securities. See Note 7 for additional information.

Debt Issuance Costs

These costs are recorded on the balance sheet and amortized over the term of the associated debt using the straight-line method which generally approximates the effective yield method. Amortization expense, including write-off of debt issuance costs, for the years ended December 31, 2014, 2013, and 2012 was approximately $7.4 million, $8.3 million and $3.6 million, respectively.

Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties due to third parties. Oil and natural gas revenues are recorded using the sales method. Under this method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent there is an imbalance in excess of the proportionate share of the remaining recoverable reserves on the underlying properties. No significant imbalances existed at December 31, 2014 or 2013.

The following individual customers each accounted for 10% or more of total reported revenues for the period indicated:

	Years Ending December 31,		
	2014	**2013**	**2012**
Consolidated & Combined:			
Energy Transfer Equity, L.P. and subsidiaries	33%	35%	13%
MRD Segment:			
Energy Transfer Equity, L.P. and subsidiaries	73%	77%	39%
Sunoco, Inc. (1)	n/a	n/a	15%
Dominion Gas Ventures LP	n/a	n/a	15%

MEMP Segment:			
Sinclair Oil & Gas Company	12%	n/a	n/a
Phillips 66 (2)	13%	15%	13%
ConocoPhillips	n/a	n/a	14%

(1) Sunoco, Inc. became a subsidiary of Energy Transfer Equity, L.P. in October 2012.

(2) Phillips 66 was a subsidiary of ConocoPhillips through April 30, 2012. Accordingly, any revenues generated from Phillips 66 prior to May 1, 2012 were reported under ConocoPhillips.

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Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, collars, and put options) are used to reduce the impact of natural gas, NGL 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 the credit facilities. Every derivative instrument is recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative s fair value are recognized in earnings as we have not elected hedge accounting for any of our derivative positions.

Capitalized Interest

We capitalize interest costs to oil and gas properties on expenditures made in connection with certain projects such as drilling and completion of new oil and natural gas wells and major facility installations. Interest is capitalized only for the period that such activities are in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings. These capitalized costs are included within intangible drilling costs and amortized using the units of production method. For the year ended December 31, 2014, we capitalized $7.3 million of interest. We did not capitalize any interest in 2013 or 2012.

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.

The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable based on its technical merits. If a tax position meets such criteria, the tax effect that would be recognized by us would be the largest amount of benefit with more than 50% chance of being realized.

The evaluation of uncertain tax positions is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

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The Company has no liability for unrecognized tax benefits as of December 31, 2014 and 2013. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the consolidated statements of operations or consolidated balance sheets as of December 31, 2014. In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease within the next twelve months.

In June 2014, we recorded a deferred tax liability of approximately $43.3 million 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.

Tax audits may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which may be due upon the conclusion of these audits. Estimates of these tax liabilities are made based upon prior experience and are updated for changes in facts and circumstances. However, due to the uncertain and complex application of tax regulations, it is possible that the ultimate resolution of audits may result in liabilities which could be materially different from these estimates. See Note 15 for additional information.

Earnings Per Share

Basic earnings per share (EPS) is computed using the two-class method based on net income (loss) available to common stockholders and the average number of shares of common stock outstanding for the period. Diluted EPS includes the impact of the Company s restricted shares of common stock as they are participating securities. The Company determines the more dilutive of either the two-class method or the treasury stock method for diluted EPS. See Note 10 for additional information.

Incentive Based Compensation Arrangements

The fair value of equity-classified awards (e.g., restricted stock awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards are recognized over the requisite service or vesting period of an award based on the fair value of the award re-measured at each reporting period. Generally, no compensation expense is recognized for equity instruments that do not vest.

Prior to the restructuring transactions, the governing documents of MRD LLC and certain of its subsidiaries provided for the issuance of incentive units. The 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.

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, which may be material, in future periods. The compensation expense recognized by us related to the incentive units will be offset by a deemed capital contribution from MRD Holdco as they are remeasured at the end of each reporting period.

See Notes 11 and 12 for further information.

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Accrued Liabilities

Current accrued liabilities consisted of the following at the dates indicated (in thousands):

	December 31,	
	2014	**2013**
Accrued capital expenditures	$ 80,350	$ 48,579
Accrued lease operating expense	16,403	13,240
Accrued general and administrative expenses	8,516	14,485
Accrued ad valorem and production taxes	8,870	3,541
Accrued interest payable	24,797	11,934
Accrued environmental	2,092	577
Accrued current deferred income taxes	51,929	382
Other miscellaneous, including operator advances	6,043	5,392
	$ 199,000	$ 98,130

Supplemental Cash Flow Information

Supplemental cash flow for the periods presented (in thousands):

	For Year Ended December 31,		
	2014	**2013**	**2012**
Supplemental cash flows:			
Cash paid for interest, net of amounts capitalized	$ 130,732	$ 61,140	$ 23,525
Income tax paid	838	168	22
Noncash investing and financing activities:			
Change in capital expenditures in payables and accrued liabilities	31,771	41,017	17,158
Assumptions of asset retirement obligations related to properties acquired or drilled	5,420	4,227	7,962
Contribution of oil and gas properties from NGP affiliate			6,893
Accrued distribution to NGP affiliates related to Cinco Group acquisitions		4,352	
Contribution related to sale of assets to NGP affiliate restricted cash			2,013
Accrued equity offering costs			171

Distributions to noncontrolling interests		47
Repurchase of equity under repurchase program	3,425	
Accounts receivable related to acquisitions	9,569	

New Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition guidance, including industry-specific guidance. The core principle of this standard is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this

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core principle, the standard provides a five-step analysis of transactions to determine when and how revenue is recognized. Other major provisions include the capitalization and amortization of certain contract costs, ensuring the time value of money is considered in the transaction price, and allowing estimates of variable consideration to be recognized before contingencies are resolved in certain circumstances. This guidance also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity s contracts with customers. The new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Early application is prohibited. The standard permits the use of either the retrospective or cumulative effect transition method. This guidance will be applicable to the Company beginning on January 1, 2017. The Company is currently assessing the impact that adopting this new accounting guidance will have on its consolidated financial statements and footnote disclosures.

Reporting Discontinued Operations. In April 2014, the FASB issued an accounting standards update that changes the criteria for determining when disposals can be presented as discontinued operations and modifies discontinued operations disclosures. The new guidance now defines a discontinued operation as (i) a disposal of a component or group of components that is disposed of or is classified as held for sale and represents a strategic shift that has (or will have) a major effect on an entity s operations and financial results or (ii) an acquired business or nonprofit activity that is classified as held for sale on the date of acquisition. We will adopt this guidance and apply the disclosure requirements prospectively beginning on January 1, 2015.

Amendments to Consolidation Analysis. In February 2015, the FASB issued an accounting standards update to improve consolidation guidance for certain types of legal entities. The guidance modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities, eliminates the presumption that a general partner should consolidate a limited partnership, affects the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships, and provides a scope exception from consolidation guidance for certain money market funds. These provisions are effective for annual reporting periods beginning after December 15, 2015, and interim periods within those annual periods, with early adoption permitted. These provisions may also be adopted using either a full retrospective or a modified retrospective approach. Although the Company is currently assessing the impact of adopting this new accounting guidance will have on its consolidated financial statements and footnote disclosures, we expect that MEMP will become a VIE. 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.

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Company s financial position, results of operations and cash flows.

Note 3. Acquisitions and Divestitures

The third party acquisitions discussed below were accounted for under the acquisition method of accounting. Accordingly, we, our predecessor, and the previous owners conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while acquisition costs associated with the acquisitions were expensed as incurred. The operating revenues and expenses of acquired properties are included in the accompanying financial statements from their respective closing dates forward. The transactions were financed through equity offerings, capital contributions and borrowings under credit facilities.

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The fair values of oil and natural gas properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural properties include estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital.

MEMP has consummated several common control acquisitions since completing its initial public offering in December 2011, as further discussed in Note 13, from certain affiliates of NGP. These acquisitions were each accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the net assets acquired were recorded at historical cost.

Acquisition-related costs

Acquisition-related costs for both related party and third party transactions are included in general and administrative expenses in the accompanying statements of operations for the periods indicated below (in thousands):

For the Year Ended December 31,		
2014	**2013**	**2012**
$6,668	$8,313	$4,538

2014 Acquisitions

On December 30, 2014, MRD acquired certain oil and natural gas producing properties from third parties in the Terryville Complex for approximately $71.9 million, including estimated customary post-closing adjustments (the Louisiana Acquisition).

During the fourth quarter 2014, MRD acquired incremental interests in certain oil and gas properties and leases in the Terryville Complex from third parties in four separate transactions for an aggregate purchase price of approximately $24.0 million.

On July 1, 2014, MEMP consummated a transaction to acquire certain oil and natural gas liquids properties from a third party in Wyoming for an aggregate purchase price of approximately $906.1 million, including estimated post-closing adjustments (the Wyoming Acquisition). Revenues of $72.0 million were recorded in the statement of operations generated earnings of approximately $22.9 million related to the Wyoming Acquisition subsequent to the closing date.

On March 25, 2014, MEMP closed a transaction to acquire certain oil and natural gas producing properties from a third party in the Eagle Ford for approximately $168.1 million (the Eagle Ford Acquisition). In addition, MEMP acquired a 30% interest in the seller s Eagle Ford leasehold. During the year ended December 31, 2014, revenues of approximately $36.5 million were recorded in the statement of operations related to the Eagle Ford Acquisition subsequent to the closing date and MEMP generated earnings of approximately $16.3 million.

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The following table summarizes the fair value assessment of the assets acquired and liabilities assumed as of the acquisition dates (in thousands):

	MRD Louisiana Acquisition	MEMP Eagle Ford Acquisition	MEMP Wyoming Acquisition
Oil and gas properties	$ 72,141	$ 168,606	$ 930,168
Asset retirement obligations	(271)	(285)	(3,980)
Revenue Payable			(375)
Accrued liabilities		(250)	(19,693)
Total identifiable net assets	$ 71,870	$ 168,071	$ 906,120

The following unaudited pro forma combined results of operations are provided for the year ended December 31, 2014 and 2013 as though the Wyoming Acquisition had been completed on January 1, 2013. The unaudited pro forma financial information was derived from the historical combined statements of operations of the Company and the previous owners and adjusted to include: (i) the revenues and direct operating expenses associated with oil and gas properties acquired, (ii) depletion expense applied to the adjusted basis of the properties acquired and (iii) interest expense on additional borrowings necessary to finance the acquisition. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of expected future results of operations.

	For the Year Ended December 31, 2014	2013
	(In thousands, except per share amounts)	
Revenues	$ 990,544	$ 761,443
Net income (loss)	(602,044)	257,839
Basic earnings per share	$ (4.08)	$
Diluted earnings per share	$ (4.08)	$

2014 Divestitures

On May 9, 2014, MRD LLC sold certain producing and non-producing properties in the Mississippian oil play of Northern Oklahoma to a third party for approximately $7.6 million and recorded a loss of $3.2 million.

2013 Acquisitions

On April 30, 2013, WildHorse Resources purchased certain oil and gas properties and leases in Louisiana from a third party for approximately $67.1 million.

MEMP closed two separate transactions during 2013 to acquire certain oil and natural gas properties from third parties in East Texas (the East Texas Acquisition) and the Rockies (the Rockies Acquisition) for

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approximately $29.4 million in aggregate. The East Texas Acquisition closed on September 6, 2013 and the Rockies Acquisition closed on August 30, 2013.

	Louisiana Acquisition	East Texas Acquisition	Rockies Acquisition
Oil and gas properties	$ 68,887	$ 9,974	$ 20,744
Asset retirement obligation	(1,789)	(78)	(1,163)
Accrued liabilities			(118)
Total identifiable net assets	$ 67,098	$ 9,896	$ 19,463

During 2013, Propel Energy acquired incremental interests in certain oil and gas properties and leases in the Hendrick Field located in Winkler County, Texas from third parties in three separate transactions for an aggregate purchase price of approximately $9.3 million.

2013 Divestitures

On January 1, 2013, Tanos sold a natural gas gathering pipeline located in East Texas, which it had originally acquired in April 2010, to a privately held gas transportation company for a minimum purchase price of $1.5 million. The maximum allowable additional proceeds are $2.0 million. The contingent consideration is based on the natural gas pipeline servicing any new wells that Tanos drills in the area over the following three years. The contingent consideration portion of an arrangement is recorded when the consideration is determined to be realizable. Tanos recorded an aggregate gain of approximately $1.4 million related to this transaction, of which $0.4 million was contingent consideration. During 2013, Tanos also sold certain non-operated oil and gas properties for $2.9 million and recorded a gain of $1.4 million.

On May 10, 2013, Black Diamond entered into a purchase and sale agreement with a third party to sell certain of its Wyoming oil and gas properties with an estimated net book value of $39.8 million for $33.0 million, before customary adjustments. As a result, Black Diamond recorded a loss on the sale of $6.8 million. This transaction closed on June 4, 2013.

During 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, which exceeded the net book value of the properties sold by $89.5 million. The transaction closed on July 31, 2013.

2012 Acquisitions

On May 1, 2012, MEMP and WildHorse jointly acquired operating and non-operating interests in certain oil and natural gas properties located in East Texas and North Louisiana from an undisclosed third party seller (Undisclosed Seller Acquisition) for a final net purchase price of approximately $112.1 million. These properties are located primarily in Polk County, Texas and Lincoln and Claiborne Parishes, Louisiana. During the year ended December 31, 2012, approximately $22.1 million of revenue and $9.2 million of earnings were recorded in the statement of operations related to the Undisclosed Seller Acquisition subsequent to the closing date.

On September 28, 2012, MEMP acquired certain oil and natural gas properties in East Texas from Goodrich Petroleum Corporation (Goodrich Acquisition) for a final net purchase price of $90.4 million after customary post-closing adjustments. The effective date of this transaction was July 1, 2012. This transaction was financed with borrowings under MEMP s revolving credit facility. These properties are located in the East Henderson

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field of Rusk County, Texas. During the year ended December 31, 2012, approximately $4.6 million of revenue and $2.0 million of earnings were recorded in the statement of operations related to the Goodrich Acquisition subsequent to the closing date.

Collectively, the previous owners consummated multiple acquisitions during 2012 by acquiring operating and non-operating interests in certain oil and natural gas properties primarily located in various Texas and New Mexico counties for an aggregate adjusted purchase price of $147.9 million, the largest of which was completed in July by Stanolind. In July 2012, Stanolind completed an acquisition of working interests, royalty interests and net revenue interests (the Menemsha Acquisition) located in various counties in Texas for a final net purchase price of $74.7 million. During the year ended December 31, 2012, approximately $4.9 million of revenue and $0.9 million of earnings were recorded in the statement of operations related to the Menemsha Acquisition subsequent to the closing date.

The following table summarizes the fair value of the assets acquired and liabilities assumed as of each acquisition date (in thousands).

	Undisclosed Seller Acquisition	Goodrich Acquisition	Menemsha Acquisition	Other Acquisitions
Oil and gas properties	$ 115,633	$ 91,187	$ 75,114	$ 77,764
Prepaid expenses and other current assets		425		
Revenues payable	(1,602)	(875)		
Asset retirement obligation	(1,592)	(161)	(408)	(4,558)
Accrued liabilities	(297)	(153)		
Total identifiable net assets	$ 112,142	$ 90,423	$ 74,706	$ 73,206

The following unaudited pro forma combined results of operations are provided for the year ended December 31, 2012 (in thousands) as though the Undisclosed Seller Acquisition, Goodrich Acquisition, and Menemsha Acquisition had been completed on January 1, 2011. The unaudited pro forma financial information was derived from our historical combined statements of operations and adjusted to include: (i) the revenues and direct operating expenses associated with oil and gas properties acquired, (ii) depletion expense applied to the adjusted basis of the properties acquired and (iii) interest expense on additional borrowings necessary to finance the acquisitions. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transactions occurred on the basis assumed above, nor is such information indicative of expected future results of operations.

Revenue	$ 431,060
Net income	40,940

During 2012, we also acquired certain interests in oil and gas properties through several individually immaterial acquisitions for an aggregate purchase price of $10.2 million.

2012 Divestitures

During 2012, certain of our subsidiaries sold certain interests in oil and gas properties for an aggregate $3.3 million. Losses of approximately $0.1 million were recognized related to these divestures.

On July 11, 2012, the previous owners completed the sale of a portion of its oil and gas assets located in Garza County, Texas to a third party for $26.1 million and recognized a gain of approximately $7.6 million. On

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September 18, 2012, the previous owners completed the sale of a portion of its oil and gas assets located in Ector County, Texas to a third party for $4.7 million and recognized a gain of approximately $2.2 million.

The majority of the proceeds generated from these sales were used to acquire operating and non-operating interests in certain oil and natural gas properties located primarily in various Texas and New Mexico counties.

Note 4. Fair Value Measurements of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is one in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. At December 31, 2014 and 2013, all of the derivative instruments reflected on the accompanying balance sheets were considered Level 2.

Level 3 Measure based on prices or valuation models that require inputs that are both significant to the fair value measurement and are less observable from objective sources (i.e., supported by little or no market activity).

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The carrying values of cash and cash equivalents, accounts receivables, accounts payables (including accrued liabilities) and amounts outstanding under long-term debt agreements with variable rates included in the accompanying balance sheets approximated fair value at December 31, 2014 and December 31, 2013. The fair value estimates are based upon observable market data and are classified within Level 2 of the fair value hierarchy. These assets and liabilities are not presented in the following tables. See Note 8 for the estimated fair value of our outstanding fixed-rate debt.

The fair market values of the derivative financial instruments reflected on the balance sheets as of December 31, 2014 and December 31, 2013 were based on estimated forward commodity prices (including nonperformance risk) and forward interest rate yield curves. Nonperformance risk is the risk that the obligation related to the derivative instrument will not be fulfilled. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement in its entirety. The significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

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The following table presents the derivative assets and liabilities that are measured at fair value on a recurring basis at December 31, 2014 and December 31, 2013 for each of the fair value hierarchy levels:

	Fair Value Measurements at December 31, 2014 Using			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
	(In thousands)			
Assets:				
Commodity derivatives	$	$ 845,759	$	$ 845,759
Interest rate derivatives		1,305		1,305
Total assets	$	$ 847,064	$	$ 847,064
Liabilities:				
Commodity derivatives	$	$ 71,639	$	$ 71,639
Interest rate derivatives		3,289		3,289
Total liabilities	$	$ 74,928	$	$ 74,928

	Fair Value Measurements at December 31, 2013 Using			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
	(In thousands)			
Assets:				
Commodity derivatives	$	$ 105,054	$	$ 105,054
Interest rate derivatives		884		884
Total assets	$	$ 105,938	$	$ 105,938
Liabilities:				

Commodity derivatives	$	$ 58,234	$	$ 58,234
Interest rate derivatives		5,590		5,590
Total liabilities	$	$ 63,824	$	$ 63,824

See Note 5 for additional information regarding our derivative instruments.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis as reflected on the balance sheets. The following methods and assumptions are used to estimate the fair values:

The fair value of asset retirement obligations (AROs) is based on discounted cash flow projections using numerous estimates, assumptions, and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate; and inflation rates. See Note 6 for a summary of changes in AROs.

If sufficient market data is not available, the determination of the fair values of proved and unproved properties acquired in transactions accounted for as business combinations are prepared by utilizing estimates of discounted cash flow projections. The factors to determine fair value include, but are not

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limited to, estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital. The fair value of supporting equipment, such as plant assets, acquired in transactions accounted for as business combinations are commonly estimated using the depreciated replacement cost approach.

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. 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.

During the year ended December 31, 2014, the MRD Segment recognized $24.6 million of impairments. The impairments primarily related to certain properties located in the Rockies as well as 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 declining commodity prices. During the year ended December 31, 2014, MEMP recognized $407.5 million of impairments. The impairments primarily related to certain properties located 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. In the Permian Basin the impairments were in due to a downward revision of estimated proved reserves based on declining commodity prices and updated well performance data. In South Texas, the impairments were in due to a downward revision of estimated proved reserves based on declining commodity prices and increased operating costs. In East Texas, the impairments were due to downward revisions based on declining commodity prices. The carrying value of the: (i) Permian Basin properties after the $234.2 million impairment was approximately $88.7 million; (ii) East Texas properties after the $107.6 million impairment was approximately $88.8 million; and (iii) South Texas properties after the $65.6 million impairment was $71.2 million.

During the year ended December 31, 2013, we recognized $6.6 million of impairments. The impairments related to certain properties located in South Texas. The estimated future cash flows expected 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 the year ended December 31, 2012, we recognized $28.9 million of impairments to proved oil and natural gas properties. Approximately $8.0 million related to a particular lease in the Elkhorn (Ellenburger) and Canyon Fields located in the Permian Basin as a result of a downward revision of estimated proved reserves due to unfavorable drilling results in the area. The remaining $20.9 million of impairments primarily related to certain fields in East Texas. The carrying values of these fields were determined to be unrecoverable due to a decline in gas prices.

Note 5. Risk Management and Derivative Instruments

Derivative instruments are utilized to manage exposure to commodity price and interest rate fluctuations and achieve a more predictable cash flow in connection with natural gas and oil sales from production and borrowing related activities. These transactions limit exposure to declines in prices or increases in interest rates, but also limit the benefits that would be realized if prices increase or interest rates decrease.

Certain inherent business risks are associated with commodity and interest derivative contracts, including market risk and credit risk. Market risk is the risk that the price of natural gas or oil will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the counterparty to a contract. It is our policy to enter into derivative contracts, including interest rate swaps, only

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with creditworthy counterparties, which generally are financial institutions, deemed by management as competent and competitive market makers. Some of the lenders, or certain of their affiliates, under our credit agreements are counterparties to our derivative contracts. 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 counterparties that are large financial institutions, which management believes present minimal credit risk. 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 net derivative assets of $517.1 million. After taking into effect netting arrangements, MEMP had counterparty exposure of $309.8 million related to its derivative instruments of which $109.7 million was with a single counterparty. 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, MRD had derivative assets of $255.0 million. After taking into effect netting arrangements, MRD had counterparty exposure of $155.8 million related to derivative instruments. Had certain counterparties failed completely to perform according to the terms of their existing contracts, MRD would have the right to offset $99.2 million against amounts outstanding under its revolving credit facility at December 31, 2014. See Note 8 for additional information regarding our revolving credit facilities.

Commodity Derivatives

We may use a combination of commodity derivatives (e.g., floating-for-fixed swaps, put options, costless collars, call spreads and basis swaps) to manage exposure to commodity price volatility. We recognize all derivative instruments at fair value; however, certain of our put option derivative instruments have a deferred premium, which reduces the asset. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement. At settlement, if the applicable index price is below the strike price of the put, the Company receives the difference between the strike price and the applicable index price multiplied by the contract volumes less the premium. If the applicable index price settles at or above the strike price of the put, the Company pays only the premium at settlement. During the year ended December 31, 2014, MRD restructured a portion of its commodity derivative portfolio by terminating in the money natural gas collars settling in 2015 and entering into natural gas swaps. The cash settlement receipts of $6.1 million from the termination of the collars were utilized to enhance the fixed price portion of the natural gas swaps.

We enter into natural gas derivative contracts that are indexed to NYMEX-Henry Hub and regional indices such as NGPL TXOK, TETCO STX, TGT Z1, and Houston Ship Channel in proximity to our areas of production. We also enter into oil derivative contracts indexed to a variety of locations such as NYMEX-WTI, Inter-Continental Exchange (ICE) Brent, California Midway-Sunset and other regional locations. Our NGL derivative contracts are primarily indexed to OPIS Mont Belvieu.

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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 basis swaps included in the table above is 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 Swaps

Periodically, interest rate swaps are entered into to mitigate exposure to market rate fluctuations by converting variable interest rates such as those in our credit agreements to fixed interest rates. From time to time we enter into offsetting positions to avoid being economically over-hedged. At December 31, 2014, we 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

On July 1, 2014, we elected to terminate the interest rate swaps associated with the MRD credit facility and in the aggregate paid our counterparties approximately $0.7 million. WildHorse Resources novated the interest rate swaps to MRD in connection with the closing of our initial public offering.

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Balance Sheet Presentation

The following table summarizes both: (i) the gross fair value of derivative instruments by the appropriate balance sheet classification even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the balance sheet and (ii) the net recorded fair value as reflected on the balance sheet at December 31, 2014 and 2013. There was no cash collateral received or pledged associated with our derivative instruments since most of the counterparties, or certain affiliates, to our derivative contracts are lenders under our collective credit agreements.

		Asset Derivatives		Liability Derivatives	
Type	**Balance Sheet Location**	**2014**	**2013**	**2014**	**2013**
		(In thousands)			
Commodity contracts	Short-term derivative instruments	$ 378,908	$ 21,759	$ 38,852	$ 19,739
Interest rate swaps	Short-term derivative instruments		845	3,289	3,287
Gross fair value		378,908	22,604	42,141	23,026
Netting arrangements	Short-term derivative instruments	(38,852)	(13,315)	(38,852)	(13,315)
Net recorded fair value	Short-term derivative instruments	$ 340,056	$ 9,289	$ 3,289	$ 9,711
Commodity contracts	Long-term derivative instruments	$ 466,851	$ 83,295	$ 32,787	$ 38,495
Interest rate swaps	Long-term derivative instruments	1,305	39		2,303
Gross fair value		468,156	83,334	32,787	40,798
Netting arrangements	Long-term derivative instruments	(32,787)	(34,718)	(32,787)	(34,718)
Net recorded fair value	Long-term derivative instruments	$ 435,369	$ 48,616	$	$ 6,080

(Gains) & Losses on Derivatives

All gains and losses, including changes in the derivative instruments fair values, have been recorded in the accompanying statements of operations since derivative instruments are not designated as hedging instruments for accounting and financial reporting purposes. The following table details the gains and losses related to derivative instruments for the years ending December 31, 2014, 2013, and 2012:

	Statements of	**For the Years Ended December 31,**		
	Operations Location	**2014**	**2013**	**2012**

		(In thousands)		
Commodity derivative contracts	(Gain) loss on commodity derivatives	$ (749,988)	$ (29,294)	$ (34,905)
Interest rate derivatives	Interest expense, net	145	(239)	5,582

Note 6. Asset Retirement Obligations

Asset retirement obligations primarily relate to our portion of future plugging and abandonment of wells and related facilities.

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The following table presents the changes in the asset retirement obligations for the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
		(In thousands)	
Asset retirement obligations at beginning of period	$ 111,769	$ 102,380	$ 90,699
Liabilities added from acquisitions or drilling	5,420	4,227	7,962
Liabilities removed upon sale of wells	(669)	(1,765)	(1,931)
Liabilities removed upon plugging and abandoning	(588)	(170)	(119)
Revisions	293	1,516	760
Accretion expense	6,306	5,581	5,009
Asset retirement obligations at end of period	122,531	111,769	102,380
Less: Current portion		90	390
Asset retirement obligations long-term portion	$ 122,531	$ 111,679	$ 101,990

Note 7. Restricted Investments

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 and gas properties owned by MEMP.

The components of the restricted investment balance are as follows at December 31, 2014 and 2013:

	2014	2013
	(In thousands)	
BOEM platform abandonment (See Note 16)	$ 69,954	$ 66,373
BOEM lease bonds	794	794
SPBPC Collateral:		
Contractual pipeline and surface facilities abandonment	2,701	2,306
California State Lands Commission pipeline right-of-way bond	3,005	3,005
City of Long Beach pipeline facility permit	500	500
Federal pipeline right-of-way bond	307	307
Port of Long Beach pipeline license	100	100
Restricted investments	$ 77,361	$ 73,385

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Note 8. Long Term Debt

The following table presents our consolidated debt obligations at the dates indicated. The MEMP Segment debt included in the table below is nonrecourse to the Company.

	December 31, 2014	December 31, 2013
	(In thousands)	
MRD Segment:		
MRD $2.0 billion revolving credit facility, variable-rate, due June 2019	$ 183,000	$
WildHorse Resources $1.0 billion revolving credit facility, variable-rate, terminated June 2014		203,100
WildHorse Resources $325.0 million second lien term facility, variable-rate, terminated June 2014		325,000
10.00%/10.75% senior PIK toggle notes redeemed June 2014		350,000
5.875% senior unsecured notes, due July 2022 (1)	600,000	
10.00%/10.75% senior PIK toggle notes unamortized discounts		(6,950)
Subtotal	783,000	871,150
MEMP Segment:		
MEMP $2.0 billion revolving credit facility, variable-rate, due March 2018	412,000	103,000
7.625% senior notes, fixed-rate, due May 2021 (2)	700,000	700,000
6.875% senior unsecured notes, due August 2022 (3)	500,000	
Unamortized discounts	(16,587)	(10,933)
Subtotal	1,595,413	792,067
Total long-term debt	$ 2,378,413	$ 1,663,217

(1) The estimated fair value of this fixed-rate debt was $534.0 million at December 31, 2014. The estimated fair value is based on quoted market prices and is classified as Level 2 within the fair value hierarchy.

(2) The estimated fair value of this fixed-rate debt was $563.5 million and $721.0 million at December 31, 2014 and 2013, respectively. The estimated fair value is based on quoted market prices and is classified as Level 2 within

the fair value hierarchy.

(3) The estimated fair value of this fixed-rate debt was $380.0 million at December 31, 2014. The estimated fair value is based on quoted market prices and is classified as Level 2 within the fair value hierarchy.

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Borrowing Base

Credit facilities tied to borrowing bases are common throughout the oil and gas industry. Each of the revolving credit facilities borrowing base is subject to redetermination on at least a semi-annual basis primarily based on estimated proved reserves. The borrowing base for MRD s and MEMP s revolving credit facility was the following at the date indicated:

	December 31, 2014
MRD Segment:	
MRD $2.0 billion revolving credit facility, variable-rate, due June 2019	$ 725,000
MEMP Segment:	
MEMP $2.0 billion revolving credit facility, variable-rate, due March 2018	1,440,000

MRD Revolving Credit Facility

On June 18, 2014, we, as borrower, and certain of our subsidiaries, as guarantors, entered into a revolving credit facility, which is a five-year, $2.0 billion revolving credit facility with an initial borrowing base of $725.0 million and aggregate elected commitments of $725.0 million.

We are permitted to borrow under the revolving credit facility in an amount up to the lesser of (i) the face amount of our revolving credit facility, (ii) the borrowing base or (iii) the aggregate elected commitments. The 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. Our borrowing base is subject to redetermination on a semi-annual basis based on an engineering report with respect to our estimated oil, NGL and natural gas reserves, which will take into account the prevailing oil, NGL 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. In addition, we may, subject to certain conditions, increase our aggregate elected commitments in an amount not to exceed the then effective borrowing base on or following a scheduled redetermination of our borrowing base once before the next scheduled redetermination date.

Borrowings under the revolving credit facility are secured by liens on substantially all of our properties, but in any event, not less than 80% of the total value of our oil and natural gas properties, and all of our equity interests in any future guarantor subsidiaries and all of our other assets including personal property. Additionally, borrowings bear interest, at our option, at either (i) the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus 0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the total commitment usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the total commitment usage. The unused portion of the total commitments is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to our total commitments usage.

The revolving credit facility requires maintenance of a ratio of Consolidated EBITDAX to Consolidated Net Interest Expense (as each term is determined under the MRD revolving credit facility), which we refer to as the interest coverage ratio, of not less than 2.5 to 1.0, and a ratio of consolidated current assets to consolidated current liabilities, each as determined under the revolving credit facility, which we refer to as the current ratio, of not less than 1.0 to 1.0.

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Additionally, the revolving credit facility contains various covenants and restrictive provisions that, among other things, limit our ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production and prepay certain indebtedness.

Events of default under the revolving credit facility include, but are not limited to, failure to make payments when due, breach of any covenant continuing beyond the applicable cure period, default under any other material debt, change in management or change of control, bankruptcy or other insolvency event and certain material adverse effects on our business.

MRD 5.875% Senior Unsecured Notes Offering

On July 10, 2014, MRD completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the MRD Senior Notes) at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes will accrue from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The MRD Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of our existing subsidiaries (subject to customary release provisions). The MRD Senior Notes and the guarantees of the MRD Senior Notes will rank equally with our and the guarantors existing and future senior indebtedness, will be effectively junior to all of our and the guarantors existing and future secured indebtedness (to the extent of the value of the assets securing such indebtedness), and senior in right of payment to all of our and the guarantors subordinated indebtedness. The MRD Senior Notes will be structurally subordinated to the indebtedness and other liabilities of our non-guarantor subsidiaries, including MEMP and its subsidiaries and MEMP GP.

The MRD Senior Notes are governed by an indenture dated as of July 10, 2014. The MRD Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any, to the date of redemption. The Company may also be required to repurchase the MRD Senior Notes upon a change of control. 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 MRD Senior Notes receive an investment grade rating from both of two specified ratings agencies. MEMP and its subsidiaries are not subject to these covenants. 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 the Company or the guarantors, all outstanding MRD 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 MRD Senior Notes may declare all the MRD Senior Notes to be due and payable immediately.

PIK notes

On December 18, 2013, MRD LLC and its wholly-owned subsidiary Memorial Resource Finance Corp. (MRD Finance Corp. and, together with MRD LLC, the MRD Issuers) completed a private placement of $350.0 million in aggregate principal amount of the PIK notes. The PIK notes were issued at 98% of par with a maturity date of

December 15, 2018. Net proceeds from the private offering were used: (i) to repay all indebtedness then outstanding under MRD LLC s then-existing revolving credit facility, (ii) to establish a cash reserve of $50.0 million for the payment of interest on the PIK notes, (iii) to pay a $210.0 million distribution to the Funds, and (iv) for general company purposes. Interest on the PIK notes was payable semi-annually in arrears on June 15 and December 15 of each year, commencing on June 15, 2014.

A redemption notice was delivered to the PIK notes trustee on June 16, 2014, which specified a redemption date of July 16, 2014 at a redemption price of 102% of the principal amount of the PIK notes plus accrued and

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unpaid interest thereon to the date of redemption. In connection with the closing of our initial public offering, we assumed the obligations of MRD LLC under the PIK notes indenture and the related debt security agreement. We irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee. An extinguishment loss of $23.6 million was recognized related to the redemption of the PIK notes.

WildHorse Resources Revolving Credit Facility and Second Lien Facility

On April 3, 2013, WildHorse Resources entered into an amended and restated credit agreement. This revolving credit facility provided for aggregate maximum credit amounts at any time of $1.0 billion, consisting of borrowings and letters of credit and had an initial borrowing base of $300.0 million. This revolving credit facility was due to mature on April 13, 2018. The borrowing base was subject to redetermination on at least a semi-annual basis. Borrowings under the revolving credit facility were to be secured by liens on substantially all of WildHorse Resources properties, but in any event, not less than 80% of the total value of the WildHorse Resources oil and natural gas properties.

On June 13, 2013, WildHorse Resources entered into a $325.0 million second lien term loan agreement that was due to mature on December 13, 2018. Borrowings bore interest, at the borrower s option, at either: (i) the Alternative Base Rate (as defined within each credit facility) plus 5.25% per annum or (ii) the applicable LIBOR plus 6.25% per annum. Borrowings under the second lien term loan agreement were to be secured by second-priority liens on substantially all of WildHorse Resources properties, but in any event, not less than 80% of the total value of the WildHorse Resources oil and natural gas properties. The priority of the security interests in the collateral and related creditors rights was set forth in an intercreditor agreement. The second lien term loan agreement contained customary affirmative and negative covenants, restrictive provisions and events of default.

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 onetime special $225.0 million distribution to MRD LLC. This $225.0 million distribution was subsequently distributed to the Funds.

In connection with the closing of our initial public offering, the 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.

MEMP Revolving Credit Facility & Senior Notes

Memorial Production Operating LLC (OLLC), a wholly-owned subsidiary of MEMP, is a party to a $2.0 billion revolving credit facility, which is guaranteed by MEMP and all of its current and future subsidiaries (other than certain immaterial subsidiaries).

Borrowings under the revolving credit facility are secured by liens on substantially all of MEMP s properties, but in any event, not less than 80% of the total value of MEMP s oil and natural gas properties, and all of MEMP s equity interests in OLLC and any future guarantor subsidiaries (other than San Pedro Bay Pipeline Company) and all of MEMP s other assets including personal property. Additionally, borrowings under the revolving credit facility bear interest, at MEMP s option, at: (i) the Alternative Base Rate defined as the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus

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0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the borrowing base usage, or (iii) the applicable LIBOR Market Index plus a margin that varies from 1.50% to 2.50% per annum according to the borrowing base usage. The unused portion of the borrowing base (or, if lower, the reduced commitment amount that has been elected) will be subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

On April 17, 2013, May 23, 2013 and October 10, 2013, MEMP and its wholly-owned subsidiary Memorial Production Finance Corporation (Finance Corp. and, together with MEMP, the MEMP Issuers) completed a private placement of $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 the 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 are governed by an indenture. The 2021 Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The MEMP Issuers may also be required to repurchase the 2021 Senior Notes upon a change of control. 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 2021 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, all outstanding 2021 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 2021 Senior Notes may declare all the 2021 Senior Notes to be due and payable immediately.

On July 17, 2014, the MEMP Issuers completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes (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, commencing on February 1, 2015. The indenture governing the 2022 Notes, dated as July 17, 2014, 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, 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.

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Weighted-Average Interest Rates

The following table presents the weighted-average interest rates paid on our consolidated and combined variable-rate debt obligations for the periods presented:

	For the Year Ended December 31,		
	2014	**2013**	**2012**
MRD Segment:			
MRD revolving credit facility	1.99%	n/a	n/a
MRD LLC revolver terminated December 2013	n/a	3.17%	4.11%
Classic revolving credit facility terminated November 2012	n/a	n/a	4.50%
WildHorse Resources revolver terminated June 2014	4.04%	2.30%	3.00%
WildHorse Resources second lien terminated June 2014	6.44%	7.60%	n/a
Black Diamond terminated November 2013	n/a	3.97%	3.62%
MEMP Segment:			
MEMP revolving credit facility	2.67%	3.25%	2.74%
WHT revolver terminated March 2013	n/a	2.29%	2.60%
Tanos revolver terminated April 2013	n/a	3.10%	2.31%
REO revolving credit facility terminated December 2012	n/a	n/a	3.40%
Stanolind revolver paid off by MEMP October 2013	n/a	3.52%	3.76%
Boaz revolver terminated October 2013	n/a	2.97%	3.12%
Crown revolver terminated October 2013	n/a	3.38%	4.20%
Propel Energy revolver paid off by MEMP October 2013	n/a	3.08%	3.28%

Unamortized Deferred Financing Costs

Unamortized deferred financing costs associated with our consolidated debt obligations were as follows at the dates indicated:

	December 31, 2014	December 31, 2013
	(In thousands)	
MRD Segment:		

MRD revolving credit facility	$ 4,285	$
MRD senior notes	12,455	
WildHorse Resources revolving credit facility		2,436
WildHorse Resources second lien term loan		9,030
PIK notes		8,261
MEMP Segment:		
MEMP revolving credit facility	6,468	5,413
2021 Senior Notes	13,308	15,053
2022 Senior Notes	7,958	
	$ 44,474	$ 40,193

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Note 9. Stockholders Equity and Noncontrolling Interests

Common Stock

The Company s authorized capital stock includes 600,000,000 shares of common stock, $0.01 par value per share. The following is a summary of the changes in our common shares issued for the year ended December 31, 2014:

Balance January 1, 2014	
Shares of common stock issued in connection with restructuring transactions (Note 1)	171,000,000
Shares of common stock issued in initial public offering (Note 1)	21,500,000
Shares of common stock repurchased and retired	(123,797)
Restricted common shares issued (Note 11)	1,068,422
Restricted common shares forfeited	(9,211)
Balance December 31, 2014	193,435,414

See Note 11 for additional information regarding restricted common shares that were granted in connection with our initial public offering. Restricted shares of common stock are participating securities and considered issued and outstanding on the grant date of restricted stock award.

Share Repurchase Program

In December 2014, the board of directors (Board) of the Company authorized the repurchase of up to $50.0 million of the Company s outstanding common stock from time to time on the open market, through block trades or otherwise and are subject to market conditions, as well as corporate, regulatory, and other considerations. During the year ended December 31, 2014, 123,797 shares of common stock were repurchased and retired for a total cost of approximately $2.2 million.

Subsequent event. MRD repurchased 2,764,887 shares of common stock under our repurchase program for an aggregate price of $47.8 million through March 16, 2015. MRD has retired all of the shares of common stock repurchased and the shares of common stock are no longer issued or outstanding.

Preferred Stock

Our amended and restated certificate of incorporation authorizes our Board, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $0.01 per share, covering up to an aggregate of 50,000,000 shares of preferred stock. There are no shares of preferred stock issued and outstanding as of December 31, 2014.

Dividend Policy

We do not anticipate declaring or providing any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain all future earnings, if any, for use in the operation of our business and to fund future growth. The decision whether to pay dividends in the future will be made by our Board in light of conditions then existing, including factors such as our financial condition, earnings, available cash, business opportunities, legal requirements, restrictions in our debt agreements, and other contracts and other factors our Board deems relevant.

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Noncontrolling Interests

Noncontrolling interests is the portion of equity ownership in the Company s consolidated subsidiaries not attributable to the Company and primarily consists of the equity interests held by: (i) the limited partners of MEMP, including the subordinated units held by MRD Holdco, that converted to common units in February 2015, and (ii) a third party investor in the San Pedro Bay Pipeline Company. Prior to our initial public offering, certain current or former key employees of certain of MRD LLC s subsidiaries also held equity interests in those subsidiaries.

Distributions paid to the limited partners of MEMP primarily represent the quarterly cash distributions paid to MEMP s unitholders, excluding those paid to MRD LLC. Contributions received from limited partners of MEMP primarily represent net cash proceeds received from common unit offerings.

In December 2012, MEMP sold 11,975,000 if its common units in an underwritten equity offering, which generated net cash proceeds of $194.1 million. The net proceeds from this equity offering partially funded MEMP s December 2012 acquisition.

On March 25, 2013, MEMP sold 9,775,000 of its common units in an underwritten equity offering, which generated net cash proceeds of $171.8 million after deducting underwriting discounts and offering expenses. The net proceeds from this equity offering partially funded MEMP s acquisition of all of the outstanding equity interests in WHT.

On October 8, 2013, MEMP sold 16,675,000 of its common units in an underwritten equity offering, which generated net cash proceeds of approximately $318.3 million after deducting underwriting discounts and offering expenses. The net proceeds from this equity offering were used to repay a portion of outstanding borrowings under MEMP s revolving credit facility.

On July 15, 2014, MEMP sold 9,890,000 common units in an underwritten equity offering, which generated net proceeds of approximately $220.0 million after deducting offering expenses. The net proceeds from the equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility.

On September 9, 2014, MEMP sold 14,950,000 common units in an underwritten equity offering, which generated net proceeds of approximately $321.3 million after deducting underwriting discounts and offering expenses. The net proceeds from the equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility.

In December 2014, the board of directors of MEMP GP authorized the repurchase of up to $150.0 million of MEMP s outstanding common units from time to time on the open market, through block trades or otherwise and are subject to market conditions, as well as corporate, regulatory, and other considerations. During the year ended December 31, 2014, 899,912 common units were repurchased and retired for a total cost of approximately $12.9 million.

Subsequent event. MEMP repurchased 1,909,583 common units under its repurchase program for an aggregate price of $28.5 million through February 1, 2015. MEMP has retired all common units repurchased and the common units are no longer issued or outstanding.

On April 1, 2013, Tanos management team sold its 1.066% interest in Tanos to MRD LLC and all incentive units held were forfeited. See Note 12 for further information.

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In connection with this sale, all of Tanos employees resigned and became employees of Tanos Exploration II, LLC (Tanos II), a Texas limited liability company controlled by the former management team of Tanos. Effective April 1, 2013, Tanos II entered into a transition services agreement with Tanos, whereby Tanos II would manage the operations of Tanos for up to a 6-month period of time. Tanos II is an unrelated entity.

On November 1, 2013, MRD LLC purchased the noncontrolling interests in Black Diamond, Classic GP and Classic and all incentive units were forfeited. See Note 12 for further information.

In connection with our initial public offering, certain former management members of WildHorse Resources contributed their 0.1% membership interest in WildHorse Resources as well as their incentive units in exchange for shares of our common stock and cash consideration of $30.0 million. The difference between the carrying amount of the noncontrolling interest of $0.4 million and the fair value of the consideration paid of $3.3 million was recognized directly in stockholders equity as additional paid in capital. See Note 12 for further information.

Note 10. Earnings per share

The following sets forth the calculation of earnings (loss) per share, or EPS, for the period indicated (in thousands, except per share amounts):

	For the Year Ended December 31, 2014	
Numerator:		
Net income (loss) available to common stockholders	$	(784,581)
Denominator:		
Weighted average common shares outstanding		192,498
Basic EPS	$	(4.08)
Diluted EPS (1)	$	(4.08)

(1) The Company determines the more dilutive of either the two-class method or the treasury stock method for diluted EPS. The restricted common shares were antidilutive due to net losses and excluded from the diluted EPS calculation for the year ending December 31, 2014. There were 202,623 incremental shares excluded from the computation of diluted EPS for the year ending December 31, 2014.

Our supplemental basic and diluted EPS includes earnings allocated to both previous owners and MRD LLC members for the period presented due to common control considerations. The following sets forth the calculation of our supplemental EPS, for the period indicated (in thousands, except per share amounts):

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		For the Year Ended December 31, 2014
Numerator:		
Net income (loss) attributable to Memorial Resource Development Corp.	$	(762,851)
Denominator:		
Weighted average common shares outstanding		192,498
Basic EPS	$	(3.96)
Diluted EPS (1)	$	(3.96)

(1) The Company determines the more dilutive of either the two-class method or the treasury stock method for diluted EPS. The restricted common shares were antidilutive due to net losses and excluded from the diluted EPS calculation for the year ending December 31, 2014. There were 202,623 incremental shares excluded from the computation of diluted EPS for the year ending December 31, 2014.

Note 11. Long-Term Incentive Plans

MRD

In June 2014, our Board adopted the Memorial Resource Development Corp. 2014 Long Term Incentive Plan (MRD LTIP) for the employees of the Company and the Board. The MRD LTIP became effective upon filing of a registration statement on Form S-8 with the SEC on June 18, 2014. The MRD LTIP provides for potential grants of stock options, stock appreciation rights, restricted stock awards, restricted stock units, bonus stock, dividend equivalents, performance awards, annual incentive awards, and other stock-based awards. The MRD LTIP initially limits the number of common shares that may be delivered pursuant to awards under the plan up to 19,250,000 common shares. Common shares that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The MRD LTIP will be administered by our Board or a committee thereof.

In connection with our initial public offering, our Board approved an aggregate award of 1,052,633 shares of restricted stock under the MRD LTIP to certain of our key employees, including each of our executive officers. These restricted stock awards will vest ratably on a four-year annual vesting schedule from the date of the grant and are subject to restrictions on transferability and customary forfeiture provisions. An award of 5,263 shares of restricted stock was also granted to each of our independent directors. These restricted stock awards will vest one year from the date of the grant and are also subject to restrictions on transferability and customary forfeiture provisions.

Award recipients are entitled to all the rights of absolute ownership of the restricted common shares, including the right to vote those shares and to receive dividends thereon if, as, and when declared by our Board. The term restricted common share represents a time-vested share. Such awards are non-vested until the required service period expires.

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The following table summarizes information regarding restricted common share awards granted under the MRD LTIP for the periods presented:

	Number of Shares	Weighted-Average Grant Date Fair Value per Share (1)
Restricted common shares outstanding at January 1, 2014		$
Granted (2)	1,068,422	$ 19.00
Forfeited	(9,211)	$ 19.00
Restricted common units outstanding at December 31, 2014	1,059,211	$ 19.00

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of restricted common share awards issued in 2014 was $20.3 million based on grant date market price of $19.00 per share.

The following table summarizes the amount of recognized compensation expense associated with these awards that are reflected in the accompanying statements of operations for the periods presented (in thousands):

For the Year Ended December 31, 2014
$2,804

The unrecognized compensation cost associated with restricted common share awards was an aggregate $17.3 million at December 31, 2014. We expect to recognize the unrecognized compensation cost for these awards over a weighted-average period of 3.43 years.

MEMP

In December 2011, the Memorial Production Partners GP LLC Long-Term Incentive Plan (MEMP LTIP) was adopted for employees, officers, consultants and directors of MEMP GP and any of its affiliates who perform services for MEMP. The MEMP LTIP consists of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The MEMP LTIP initially limits the number of common units that may be delivered pursuant to awards under the plan to 2,142,221 common units. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards.

The restricted common units awarded are subject to restrictions on transferability, customary forfeiture provisions and graded vesting provisions. One-third of each award generally vests on the first, second, and third anniversaries of the date of grant. Award recipients have all the rights of a unitholder in MEMP with respect to the restricted common units, including the right to receive distributions thereon if and when distributions are made by MEMP to its unitholders (except with respect to the fourth quarter 2011 distribution that was paid in February 2012). The term restricted common unit represents a time-vested unit. Such awards are non-vested until the required service period expires.

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The following table summarizes information regarding restricted common unit awards granted under the MEMP LTIP for the periods presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)	
Restricted common units outstanding at December 31, 2011		$	
Granted (2)	287,943	$	18.07
Forfeited	(2,334)	$	17.14
Restricted common units outstanding at December 31, 2012	285,609	$	18.08
Granted (3)	524,718	$	18.83
Forfeited	(11,734)	$	17.24
Vested	(91,666)	$	18.31
Restricted common units outstanding at December 31, 2013	706,927	$	18.62
Granted (4)	684,954	$	22.39
Forfeited	(38,294)	$	20.54
Vested	(260,067)	$	18.56
Restricted common units outstanding at December 31, 2014	1,093,520	$	20.93

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued in 2012 was $5.2 million based on grant date market prices ranging from of $17.14 to $18.58 per unit.
(3) The aggregate grant date fair value of restricted common unit awards issued in 2013 was $9.9 million based on grant date market prices ranging from of $18.33 to $20.35 per unit.
(4) The aggregate grant date fair value of restricted common unit awards issued in 2014 was $15.3 million based on grant date market prices ranging from of $21.99 to $23.40 per unit.

The following table summarizes the amount of recognized compensation expense associated with these awards that are reflected in the accompanying statements of operations for the periods presented (in thousands):

For the Year Ended December 31,		
2014	2013	2012
$7,874	$3,558	$1,423

The unrecognized compensation cost associated with restricted common unit awards was $16.5 million at December 31, 2014. We expect to recognize the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years. Since the restricted common units are participating securities, any distributions received by the restricted common unitholders are included in distributions to noncontrolling interests as presented on our statements of consolidated and combined cash flows.

Note 12. Incentive Units

General

Each of the governing documents of BlueStone, Tanos, WildHorse Resources, Classic, Black Diamond and MRD LLC previously provided for the issuance of incentive units. The 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.

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BlueStone, Tanos, WildHorse Resources, Classic, Black Diamond 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) had been achieved. Payouts were generally triggered after the recovery of specified members capital contributions plus a rate of return. In connection with MEMP s initial public offering in December 2011, BlueStone s Special Tier and Tier I unit holders vested in their respective awards. Tier I unit holders became eligible to participate in 16.5% of any future distributions made by BlueStone.

Vesting of the incentive units was 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 were forfeited if an employee was no longer employed. All incentive units were forfeited if a holder resigned whether the incentive units were vested or not. If the payouts had not yet occurred, then all incentive units, whether or not vested, were forfeited automatically (unless extended).

On April 1, 2013, Tanos management team sold its 1.066% interest in Tanos to MRD LLC and all incentive units held were forfeited. Compensation expense of approximately $5.8 million was recorded by Tanos and recognized as a component of general and administrative expense during the year ended December 31, 2013.

On November 1, 2013, MRD LLC purchased the noncontrolling interests in Black Diamond, Classic GP and Classic and all incentive units were forfeited. Compensation expense of approximately $12.6 million was recorded by Black Diamond, Classic GP and Classic in the aggregate during November 2013.

Compensation expense of approximately $1.0 million and $20.7 million was recorded by BlueStone and recognized as a component of incentive unit compensation expense during the year ended December 31, 2014 and 2013, respectively. No compensation expense was recorded at December 31, 2012.

In connection with the PIK notes issued in December 2013, a special distribution of $10.0 million to holders of WildHorse s Tier 1 incentive units was deemed probable of occurring. This amount was recognized as compensation expense in December 2013 with a corresponding amount in accrued liabilities on our balance sheet at December 31, 2013 as payment was not made until January 2, 2014.

In connection with our initial public offering, certain former management members of WildHorse Resources contributed their 0.1% membership interest in WildHorse Resources as well as their incentive units 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 accounted for as the acquisition of noncontrolling interests. The difference between the carrying amount of the noncontrolling interest of $0.4 million and the fair value of the consideration paid of $3.3 million was recognized directly in stockholders equity as additional paid in capital. Compensation expense of approximately $831.1 million was recognized as a component of incentive unit compensation expense during the year ended December 31, 2014 related to the incentive units, of which approximately $26.7 million was paid in cash and the remaining $804.4 million related to the issuance of our common stock.

MRD Holdco

MRD LLC incentive units were originally granted in June 2012 and February 2013. In connection with our initial public offering and the related restructuring transactions, these 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. MRD Holdco s governing documents authorize the issuance of 1,000 incentive units, of which 930 incentive units were granted in an exchange for the cancelled MRD LLC awards (the Exchanged Incentive Units).

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The holders of the Exchanged Incentive Units are eligible to participate in 9.3% of any future distributions made by MRD Holdco. The payment likelihood was deemed probable as a result of our initial public offering and the reasonable expectation that MRD Holdco will monetize the shares of our common stock it owns over an estimated three year period as market conditions permit. During 2014, we recognized $111.5 million of compensation expense offset by a deemed capital contribution from MRD Holdco and the unrecognized compensation expense of approximately $105.5 million as of December 31, 2014 will be recognized over the remaining expected service period of 2.41 years.

Subsequent to our initial public offering, MRD Holdco granted the remaining 70 incentive units to certain key employees (the Subsequent Incentive Units). The holders of the Subsequent Incentive Units are eligible to participate in 0.7% of any future distributions made by MRD Holdco once payout associated with these incentive units has been achieved. The payment likelihood was deemed probable at December 31, 2014 as a result of our initial public offering and the reasonable expectation that MRD Holdco will monetize the shares of our common stock it owns over an estimated three year period as market conditions permit. During 2014, we recognized $0.4 million of compensation expense and the unrecognized compensation expense of approximately $1.7 million as of December 31, 2014 will be recognized over the remaining expected service period of 2.41 years.

The fair value of the Exchanged and Subsequent Incentive Units will be remeasured on a quarterly basis until all payments have been made. The settlement obligation rests with MRD Holdco. Accordingly, no payments will ever be made by us related to these incentive units; however, non-cash compensation expense (income) will be allocated to us in future periods offset by capital contributions (distributions). As such, these awards are not dilutive to our stockholders.

The fair value of the incentive units was estimated using a Monte Carlo simulation valuation model with the following assumptions:

	Exchanged Incentive Units	Subsequent Incentive Units
Valuation date	12/31/2014	12/31/2014
Dividend yield	0%	0%
Expected volatility	39.54%	39.54%
Risk-free rate	0.85%	0.85%
Expected life (years)	2.41	2.41

Note 13. Related Party Transactions

Amounts due to (due from) MRD Holdco and certain affiliates of NGP at December 31, 2014 and 2013 are presented as Accounts receivable affiliates and Accounts payable affiliates in the accompanying balance sheets.

Net Profits Interest Sold to NGP

Upon the completion of the 2010 Petrohawk and Clayton Williams acquisitions, WildHorse Resources sold a net profits interest in these properties to NGPCIF. Upon the acquisition of the Petrohawk properties WildHorse Resources immediately sold a net profits interest of 6.25% for all producing well bores and the right to participate in a 3.125% net profits interest in non-producing wellbores for the subject area for $19.5 million, or $19.1 million after adjustments. Upon the acquisition of the Clayton Williams properties, WildHorse Resources immediately sold a net profits interest of 23.5% for all producing wellbores and the right to participate in a 10.0% net profits interest in non-producing wellbores for the subject area for $19.8 million, or $19.9 million after adjustments. No gain or loss was recorded from these two transactions.

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The net profits agreements for these transactions provided for a fixed fee of $20,000 per month for overhead and management in lieu of COPAS (Council of Petroleum Accountants Societies) billings. The net profits agreements did not provide for an overhead adjustment factor for this monthly charge, as suggested by COPAS. Quarterly net payments were made to NGPCIF for its net profits interest in the Petrohawk and Clayton Williams acquisitions. The net payments included credits for revenue receipts which were offset with production costs, capital expenditures and the management fee and were adjusted for any acquisition settlements received or paid and any other miscellaneous adjustments. As required by such agreements, WildHorse Resources could not collect funds owed by NGPCIF to WildHorse Resources, but WildHorse Resources could net amounts due from future quarterly payments.

As a result of these transactions, WildHorse Resources paid NGPCIF a total of $2.6 million and $2.3 million during 2013 and 2012, respectively. NGPCIF owed WildHorse Resources $0.2 million at December 31, 2013.

NGPCIF NPI Acquisition

WildHorse Resources repurchased the net profits interests discussed above from NGPCIF on February 28, 2014 for a purchase price of $63.4 million (see Note 1). This acquisition was accounted for as a combination of entities under common control at historical cost in a manner similar to the pooling of interest method. WildHorse Resources recorded the following net assets (in thousands):

Accounts receivable	$ 2,274
Oil and natural gas properties, net	40,056
Accrued liabilities	(297)
Asset retirement obligations	(277)
Net assets	$ 41,756

Due to common control considerations, the difference between the purchase price and the net assets acquired are reflected within equity as a deemed distribution to NGP affiliates.

Transactions Between the Previous Owners and NGP Affiliates

The previous owners sold certain interests in oil and gas properties offshore Louisiana on October 11, 2012 for an aggregate $40.1 million to an NGP controlled entity, of which $38.1 million was received upon closing and the remaining proceeds were released from escrow in April 2013. Due to common control considerations, the proceeds from the sale exceeded the net book value of the properties sold by $6.3 million and recognized in the equity statement as a net contribution.

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Beta Acquisition

On December 12, 2012, MEMP acquired Rise Energy Operating, Inc. (REO), which owns certain operating interests in producing and non-producing oil and gas properties offshore Southern California (the Beta Properties), from Rise for a purchase price of $270.6 million, which included $3.0 million of working capital and other customary adjustments. The Beta acquisition was funded with borrowings under MEMP s revolving credit facility and the net proceeds generated from its December 12, 2012 public offering of common units. This acquisition was accounted for as a combination of entities under common control at historical cost in a manner similar to the pooling of interest method. MEMP recorded the following net assets (in thousands):

Cash and cash equivalents	$ 6,021
Accounts receivable	16,284
Short-term derivative instruments, net	2,926
Prepaid expenses and other current assets	4,521
Oil and natural gas properties, net	108,342
Restricted investments	68,009
Accounts payable	(9,092)
Accrued liabilities	(9,140)
Asset retirement obligations	(58,746)
Credit facilities	(28,500)
Deferred tax liability	(1,674)
Noncontrolling interest	(5,255)
Net assets	$ 93,696

An affiliate of REO collected a management fee for providing administrative services to REO. These administrative services included accounting, business development, finance, legal, information technology, insurance, government regulations, communications, regulatory, environmental and human resources services. REO incurred and paid management fees of $1.6 million during the year ended December 31, 2012. These management fees are presented as a component of general and administrative costs and expenses in the accompanying statements of operations.

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October 2013 Cinco Group Acquisition

On October 1, 2013, MEMP acquired, through equity and asset transactions, oil and natural gas properties primarily in the Permian Basin, East Texas and the Rockies from MRD LLC and certain affiliates of NGP for an aggregate purchase price of approximately $603 million (subject to customary post-closing adjustments), of which approximately $507.1 million was received by certain affiliates of NGP. We refer to this transaction as the Cinco Group acquisition. The Cinco Group acquisition was funded with borrowings under MEMP s revolving credit facility. The Cinco Group acquisition was accounted for as a combination of entities under common control at historical cost in a manner similar to the pooling of interest method.

Cash and cash equivalents	$ 2,820
Accounts receivable	5,184
Prepaid expenses and other current assets	1,454
Oil and natural gas properties, net	342,759
Long-term derivative instruments, net	(826)
Other long-term assets	344
Accounts payable	(2,346)
Revenue payable	(2,910)
Accrued liabilities	(1,799)
Short-term derivative instruments, net	(1,828)
Asset retirement obligations	(9,606)
Credit facilities	(151,690)
Net assets	$ 181,556

Other Acquisitions or Dispositions

On March 10, 2014, BlueStone sold certain interests in oil and gas properties in McMullen, Webb, Zapata, and Hidalgo Counties located in South Texas to BlueStone Natural Resources II, LLC, an NGP controlled entity. Total cash consideration received by BlueStone was approximately $1.2 million, which exceeded the net book value of the properties sold by $0.5 million. Due to common control considerations, the $0.5 million was recognized in the equity statement as a contribution.

On March 28, 2014, MRD Royalty acquired certain interests in oil and gas properties in Gonzales and Karnes Counties located in South Texas from Propel Energy for $3.3 million.

On June 18, 2014, in connection with our initial public offering and the related restructuring transactions (see Note 1), WHR Management Company was sold by WildHorse Resources to an affiliate of the Funds for net book value. The net book value of the assets sold was as follows (in thousands):

Cash and cash equivalents	$ 33,001
Restricted cash	300
Accounts receivable	5,256
Prepaid expenses and other current assets	379
Property, plant and equipment, net	3,410
Other long-term assets	4
Accounts payable	(19,959)
Accounts payable affiliates	(17,099)
Accrued liabilities	(5,061)
Net assets	$ 231

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Related Party Agreements

We and certain of our affiliates have entered into various documents and agreements. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm s-length negotiations.

Registration Rights Agreement

In connection with the closing of our initial public offering, we entered into a registration rights agreement with MRD Holdco and former management members of WildHorse Resources, Jay Graham (Graham) and Anthony Bahr (Bahr). Pursuant to the registration rights agreement, we have agreed to register the sale of shares of our common stock under certain circumstances.

Voting Agreement

In connection with the closing of our initial public offering, we entered into a voting agreement with MRD Holdco, WHR Incentive LLC, a limited liability company beneficially owned by Messrs. Bahr and Graham, and certain former management members of WildHorse Resources, who contributed their ownership of WildHorse Resources to us in the restructuring transactions. Among other things, the voting agreement provides that those former management members of WildHorse Resources will vote all of their shares of our common stock as directed by MRD Holdco. The voting agreement also prohibits the transfer of any shares of our common stock by the former management members of WildHorse Resources until after the termination of the services agreement described below; provided, however, that the former management members of WildHorse Resources (other than Messrs. Bahr and Graham) may transfer their shares of our common stock after the 180 day lock-up period has expired and these transfer restrictions will not prohibit Messrs. Bahr and Graham from exercising piggyback registration rights under the registration rights agreement described above.

Services Agreement

In connection with the closing of our initial public offering, we entered into a services agreement with WildHorse Resources and WHR Management Company, pursuant to which WHR Management Company would provide operating and administrative services to us for twelve months relating to the Terryville Complex. In exchange for such services, we paid a monthly management fee to WHR Management Company of approximately $1.0 million excluding third party COPAS income credits.

Upon the closing of our initial public offering, WHR Management Company became a subsidiary of WildHorse Resources II, LLC, an affiliate of the Company. NGP and certain former management members of WildHorse Resources own WHR II.

Subsequent event. We terminated the services agreement as of March 1, 2015.

WildHorse Management Services Agreement

WHR II is an independent energy company engaged in the acquisition, exploration, and development of natural gas and crude oil properties. WHR II is a related party and was organized in the State of Delaware on June 3, 2013. A management services agreement was executed on August 8, 2013, where WildHorse Resources provided general, administrative and employee services to WHR II. On August 8, 2013, a management agreement between WildHorse Resources and WHR II was executed where WildHorse was appointed the manager for WHR II with responsibilities included administrative and land services, operator services and financial and accounting services. As operator, WildHorse Resources received operated and non-operated revenues on behalf of WHR II and billed and received joint interest billings. In addition, WildHorse Resources

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paid for lease operating expenses and drilling costs on behalf of WHR II. On August 8, 2013, an asset and cost sharing agreement between WildHorse Resources and WHR II was executed. As part of the agreement, shared WildHorse Resources costs were allocated between WildHorse Resources and WHR II in accordance with a sharing ratio. The sharing ratio is based on the previous quarter s capital expenditures and number of operated wells. Company specific costs were billed directly to the appropriate entity. As a result of these agreements, WildHorse Resources received net payments of $4.4 million from WHR II in 2013. WildHorse Resources owed WHR II $2.4 million as of December 31, 2013. These agreements were terminated in connection with our initial public offering.

Cinco Group Transition Service Agreements

MEMP entered into transition service agreements with Propel Energy, Stanolind, and Boaz Energy Partners to provide operating and administrative services to MEMP with respect to the acquired properties. The term of these agreements were from October 1, 2013 through February 28, 2014. MEMP paid transition service fees of approximately $0.8 million in the aggregate under these agreements.

Other Agreements

Effective March 1, 2012, BlueStone entered into an agreement with CH4 Energy III, LLC, an NGP controlled entity, to sell an undivided 25% 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 $7.0 million, which exceeded the net book value of the properties sold by $6.4 million. Due to common control considerations, the $6.4 million was recognized in the equity statement as a contribution. The transaction closed on July 13, 2012.

A company affiliated with one of the Classic s employees provided certain land-related services to Classic. Classic paid approximately $1.0 million to this affiliated company for these services in 2012.

Certain of the Cinco Group entities entered into advisory service, reimbursement, and indemnification agreements with NGP. These agreements generally required that an annual advisory fee be paid to NGP. Fees paid under these agreements for the years ended December 31, 2013 and 2012 were approximately $0.3 million and $0.4 million, respectively. Certain of the Cinco Group entities also paid a financing fee equal to a percentage of the capital contributions raised by NGP. These fees were considered a syndication cost and reduced equity contributions for financing fees paid. Fees for the year ended December 31, 2012 was approximately $0.4 million. There were no fees for the year ended December 31, 2013.

During 2012, the previous owners received an equity contribution of $6.9 million of oil and gas properties in the Hendricks Field located in the Permian Basin of Texas by an NGP controlled entity. Due to common control considerations, this equity contribution was recorded at historical cost of the properties.

During 2012, Boaz reimbursed a member of its management team approximately $0.3 million in general, administrative, and lease operating expenses related to an oral lease agreement between the member of management and a third party for a field office and yard located in Bronte, Texas.

Gas Processing Agreement

On March 17, 2014, WildHorse Resources entered into a gas processing agreement with PennTex North Louisiana, LLC (PennTex). PennTex is a joint venture among certain affiliates of NGP in which MRD Holdco owns, through its subsidiary MRD Midstream LLC, a minority interest. Once PennTex s processing plant

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becomes operational, it will process natural gas produced from wells located on certain leases owned by us in the state of Louisiana. The agreement has a 15-year primary term, subject to one-year extensions at either party s election. We will pay PennTex a monthly fee, subject to an annual inflationary escalation, based on volumes of natural gas delivered and processed. Once the plant is declared operational, we will be obligated to pay a minimum processing fee equal to approximately $18.3 million on an annual basis, subject to certain adjustments and conditions. The gas processing agreement requires that the processing plant be operational no later than November 1, 2015.

Classic Pipeline Gas Gathering Agreement & Water Disposal Agreement

On November 1, 2011, Classic Hydrocarbons Operating, LLC (Classic Operating), which became our wholly-owned subsidiary in connection with the restructuring transactions, and Classic Pipeline entered into a gas gathering agreement. Pursuant to the gas gathering agreement, Classic Operating dedicated to Classic Pipeline all of the natural gas produced (up to 50,000 MMBtus per day) on the properties operated by Classic Operating within certain counties in Texas through 2020, subject to one-year extensions at either party s election. On May 1, 2014, Classic Operating and Classic Pipeline amended the gas gathering agreement with respect to Classic Operating s remaining assets located in Panola and Shelby Counties, Texas. Under the amended gas gathering agreement, Classic Operating agreed to pay a fee of (i) $0.30 per MMBtu, subject to an annual 3.5% inflationary escalation, based on volumes of natural gas delivered and processed, and (ii) $0.07 per MMBtu per stage of compression plus its allocated share of compressor fuel. The amended gas gathering agreement has a term until December 31, 2023, subject to one-year extensions at either party s election.

On May 1, 2014, Classic Operating and Classic Pipeline entered into a water disposal agreement. The water disposal agreement has a three-year term, subject to one-year extensions at either party s election. Under the water disposal agreement, Classic Operating agreed to pay a fee of $1.10 per barrel for each barrel of water delivered to Classic Pipeline.

Note 14. Business Segment Data

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

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 historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

We evaluate segment performance based on Adjusted EBITDA. Adjusted EBITDA is defined as net income (loss), plus interest expense; loss on extinguishment of debt; income tax expense; depreciation, depletion and amortization (DD&A); impairment of goodwill and long-lived properties; accretion of asset retirement obligations (AROs); losses on commodity derivative contracts and cash settlements received; losses on sale of properties; incentive-based compensation expenses; exploration costs; provision for environmental remediation; equity loss from MEMP (MRD Segment only); cash distributions from MEMP (MRD Segment only); acquisition related costs; amortization of investment premium; and other non-routine items, less interest income; income tax benefit; gains on commodity derivative contracts and cash settlements paid; equity income from MEMP (MRD Segment only); gains on sale of assets and other non-routine items.

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Financial information presented for the MEMP business segment is derived from the underlying consolidated and combined financial statements of MEMP that are publicly available.

Segment revenues and expenses include intersegment transactions. Our combined totals reflect the elimination of intersegment transactions.

In the MRD Segment s individual financial statements, investments in the MEMP Segment that are included in the consolidated and combined financial statements are accounted for by the equity method.

The following table presents selected business segment information for the periods indicated (in thousands):

	MRD	MEMP	Other, Adjustments & Eliminations	Consolidated & Combined Totals
Total revenues:				
For the Year ended December 31, 2014	$ 405,286	$ 494,105	$ (46)	$ 899,345
For the Year ended December 31, 2013	231,558	343,616	(151)	575,023
For the Year ended December 31, 2012	138,814	258,423	(369)	396,868
Adjusted EBITDA: (1)				
For the Year ended December 31, 2014	343,976	309,901	(6,144)	647,733
For the Year ended December 31, 2013	197,903	222,185	(25,232)	394,856
For the Year ended December 31, 2012	132,105	179,334	(23,447)	287,992
Segment assets: (2)				
As of December 31, 2014	1,632,313	2,930,559	30,675	4,593,547
As of December 31, 2013	1,281,134	1,552,307	(4,280)	2,829,161
Total cash expenditures for additions to long-lived assets:				
For the Year ended December 31, 2014	521,038	1,348,095		1,869,133
For the Year ended December 31, 2013	267,870	200,577		468,447
For the Year ended December 31, 2012	249,526	387,160		636,686

(1) Adjustments and eliminations for the years ended December 31, 2014, 2013 and 2012 include amounts related to the MRD Segment s equity investments in the MEMP Segment as well the elimination of $6.1 million, $26.0 million and $19.3 million of cash distributions that MEMP paid MRD Segment for the years ended December 31, 2014, 2013 and 2012, respectively, related to MRD Segment s partnership interests in MEMP.

(2) Adjustments and eliminations primarily represent the elimination of the MRD Segment s equity investments in the MEMP Segment. The adjustment at December 31, 2014 and 2013 also includes $46.0 million and $49.9 million, respectively related to an impairment recognized by the MEMP Segment during 2013. This impairment did not

exist on a consolidated basis.

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Calculation of Reportable Segments Adjusted EBITDA

	For the Year Ended December 31, 2014		
	MRD	MEMP	Combined Totals
		(In thousands)	
Net income (loss)	$ (762,926)	$ 118,079	$ (644,847)
Interest expense, net	50,283	83,550	133,833
Loss on extinguishment of debt	37,248		37,248
Income tax expense (benefit)	99,850	1,121	100,971
DD&A	154,917	155,404	310,321
Impairment of proved oil and natural gas properties	24,576	407,540	432,116
Accretion of AROs	688	5,618	6,306
(Gain) loss on commodity derivative instruments	(257,734)	(492,254)	(749,988)
Cash settlements received (paid) on commodity derivative instruments	9,166	13,522	22,688
(Gain) loss on sale of properties	3,057		3,057
Acquisition related costs	2,305	4,363	6,668
Incentive-based compensation expense	946,753	7,874	954,627
Exploration costs	15,813	790	16,603
Provision for environmental remediation		2,852	2,852
Loss on office lease	1,180	1,442	2,622
Non-cash equity (income) loss from MEMP	12,656		12,656
Cash distributions from MEMP	6,144		6,144
Adjusted EBITDA	$ 343,976	$ 309,901	$ 653,877

MEMORIAL RESOURCE DEVELOPMENT CORP.

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	For the Year Ended December 31, 2013		
	MRD	MEMP	Combined Totals
		(In thousands)	
Net income (loss)	$ 82,243	$ 20,268	$ 102,511
Interest expense, net	27,349	41,901	69,250
Income tax expense (benefit)	1,311	308	1,619
DD&A	87,043	97,269	184,312
Impairment of proved oil and natural gas properties	2,527	54,362	56,889
Accretion of AROs	728	4,853	5,581
(Gain) loss on commodity derivative instruments	(3,013)	(26,281)	(29,294)
Cash settlements received (paid) on commodity derivative instruments	12,240	19,879	32,119
(Gain) loss on sale of properties	(82,773)	(2,848)	(85,621)
Acquisition related costs	1,584	6,729	8,313
Incentive-based compensation expense	43,279	3,558	46,837
Non-cash compensation expense		1,057	1,057
Exploration costs	1,226	1,130	2,356
Non-cash equity (income) loss from MEMP	(1,847)		(1,847)
Cash distributions from MEMP	26,006		26,006
Adjusted EBITDA	$ 197,903	$ 222,185	$ 420,088

	For the Year Ended December 31, 2012		
	MRD	MEMP	Combined Totals
		(In thousands)	
Net income (loss)	$ (14,641)	$ 46,518	$ 31,877
Interest expense, net	12,802	20,436	33,238
Income tax expense (benefit)	(178)	285	107
DD&A	62,636	76,036	138,672
Impairment of proved oil and natural gas properties	18,339	10,532	28,871
Accretion of AROs	632	4,377	5,009
(Gain) loss on commodity derivative instruments	(13,488)	(21,417)	(34,905)
Cash settlements received (paid) on commodity derivative instruments	30,188	44,111	74,299
(Gain) loss on sale of properties	(2)	(9,759)	(9,761)
Acquisition related costs	403	4,135	4,538

Incentive-based compensation expense	9,510	1,423	10,933
Amortization of investment premium		194	194
Exploration costs	7,337	2,463	9,800
Non-cash equity (income) loss from MEMP	(696)		(696)
Cash distributions from MEMP	19,263		19,263
Adjusted EBITDA	$ 132,105	$ 179,334	$ 311,439

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The following table presents a reconciliation of total reportable segments Adjusted EBITDA to net income (loss) for each of the periods indicated (in thousands):

	For the Year Ended December 31,		
	2014	**2013**	**2012**
Total Reportable Segments Adjusted EBITDA	$ 653,877	$ 420,088	$ 311,439
Adjustments to reconcile Adjusted EBITDA to net income (loss):			
Interest expense, net	(133,833)	(69,250)	(33,238)
Loss on extinguishment of debt	(37,248)		
Income tax benefit (expense)	(100,971)	(1,619)	(107)
DD&A	(314,193)	(184,717)	(138,672)
Impairment of proved oil and natural gas properties	(432,116)	(6,600)	(28,871)
Accretion of AROs	(6,306)	(5,581)	(5,009)
Gains (losses) on commodity derivative instruments	749,988	29,294	34,905
Cash settlements paid (received) on commodity derivative instruments	(22,688)	(32,119)	(74,299)
Gain (loss) on sale of properties	(3,057)	85,621	9,761
Acquisition related costs	(6,668)	(8,313)	(4,538)
Incentive-based compensation expense	(954,627)	(46,837)	(10,933)
Non-cash compensation expense		(1,057)	
Exploration costs	(16,603)	(2,356)	(9,800)
Amortization of investment premium			(194)
Cash distributions from MEMP	(6,144)	(26,006)	(19,263)
Provision for environmental remediation	(2,852)		
Loss on office lease	(2,622)		
Other non-cash equity (income) loss		784	(4,184)
Net income (loss)	$ (636,063)	$ 151,332	$ 26,997

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MEMORIAL RESOURCE DEVELOPMENT CORP.

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Included below is our consolidated and combined statement of operations disaggregated by reportable segment for the period indicated (in thousands):

	For the Year Ended December 31, 2014			
	MRD	MEMP	Other, Adjustments & Eliminations	Consolidated & Combined Totals
Revenues:				
Oil & natural gas sales	$ 404,718	$ 490,249	$	$ 894,967
Other revenues	568	3,856	(46)	4,378
Total revenues	405,286	494,105	(46)	899,345
Costs and expenses:				
Lease operating	26,695	134,654	(46)	161,303
Pipeline operating		2,068		2,068
Exploration	15,813	790		16,603
Production and ad valorem taxes	14,150	31,601		45,751
Depreciation, depletion, and amortization	154,917	155,404	3,872	314,193
Impairment of proved oil and natural gas properties	24,576	407,540		432,116
Incentive unit compensation expense	943,949			943,949
General and administrative	42,054	45,619		87,673
Accretion of asset retirement obligations	688	5,618		6,306
(Gain) loss on commodity derivative instruments	(257,734)	(492,254)		(749,988)
(Gain) loss on sale of properties	3,057			3,057
Other, net		(12)		(12)
Total costs and expenses	968,165	291,028	3,826	1,263,019
Operating income (loss)	(562,879)	203,077	(3,872)	(363,674)
Other income (expense):				
Interest expense, net	(50,283)	(83,550)		(133,833)
Loss on extinguishment of debt	(37,248)			(37,248)
Earnings from equity investments	(12,656)		12,656	

Other, net	(10)	(327)		(337)
Total other income (expense)	(100,197)	(83,877)	12,656	(171,418)
Income (loss) before income taxes	(663,076)	119,200	8,784	(535,092)
Income tax benefit (expense)	(99,850)	(1,121)		(100,971)
Net income (loss)	$ (762,926)	$ 118,079	$ 8,784	$ (636,063)

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NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

	For the Year Ended December 31, 2013			
	MRD	**MEMP**	**Other, Adjustments & Eliminations**	**Consolidated & Combined Totals**
Revenues:				
Oil & natural gas sales	$ 230,751	$ 341,197	$	$ 571,948
Other revenues	807	2,419	(151)	3,075
Total revenues	231,558	343,616	(151)	575,023
Costs and expenses:				
Lease operating	25,006	88,893	(259)	113,640
Pipeline operating		1,835		1,835
Exploration	1,226	1,130		2,356
Production and ad valorem taxes	9,362	17,784		27,146
Depreciation, depletion, and amortization	87,043	97,269	405	184,717
Impairment of proved oil and natural gas properties	2,527	54,362	(50,289)	6,600
Incentive unit compensation expense	43,279			43,279
General and administrative	38,479	43,495	105	82,079
Accretion of asset retirement obligations	728	4,853		5,581
(Gain) loss on commodity derivative instruments	(3,013)	(26,281)		(29,294)
(Gain) loss on sale of properties	(82,773)	(2,848)		(85,621)
Other, net	2	647		649
Total costs and expenses	121,866	281,139	(50,038)	352,967
Operating income (loss)	109,692	62,477	49,887	222,056
Other income (expense):				
Interest expense, net	(27,349)	(41,901)		(69,250)
Earnings from equity investments	1,066		(1,066)	
Other, net	145			145
Total other income (expense)	(26,138)	(41,901)	(1,066)	(69,105)
Income before income taxes	83,554	20,576	48,821	152,951
Income tax benefit (expense)	(1,311)	(308)		(1,619)

Net income (loss)	$ 82,243	$ 20,268	$ 48,821	$ 151,332

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NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

	For the Year Ended December 31, 2012			
	MRD	MEMP	Other, Adjustments & Eliminations	Consolidated & Combined Totals
Revenues:				
Oil & natural gas sales	$ 138,032	$ 255,608	$ (9)	$ 393,631
Other revenues	782	2,815	(360)	3,237
Total revenues	138,814	258,423	(369)	396,868
Costs and expenses:				
Lease operating	24,438	80,116	(800)	103,754
Pipeline operating		2,114		2,114
Exploration	7,337	2,463		9,800
Production and ad valorem taxes	7,576	16,048		23,624
Depreciation, depletion, and amortization	62,636	76,036		138,672
Impairment of proved oil and natural gas properties	18,339	10,532		28,871
Incentive unit compensation expense	9,510			9,510
General and administrative	28,904	30,342	431	59,677
Accretion of asset retirement obligations	632	4,377		5,009
(Gain) loss on commodity derivative instruments	(13,488)	(21,417)		(34,905)
(Gain) loss on sale of properties	(2)	(9,759)		(9,761)
Other, net	364	138		502
Total costs and expenses	146,246	190,990	(369)	336,867
Operating income (loss)	(7,432)	67,433		60,001
Other income (expense):				
Interest expense, net	(12,802)	(20,436)		(33,238)
Amortization of investment premium		(194)		(194)
Earnings from equity investments	4,880		(4,880)	
Other, net	535			535
Total other income (expense)	(7,387)	(20,630)	(4,880)	(32,897)
Income before income taxes	(14,819)	46,803	(4,880)	27,104
Income tax benefit (expense)	178	(285)		(107)

Net income (loss)	$ (14,641)	$ 46,518	$ (4,880)	$ 26,997

Note 15. Income Taxes

Income tax benefit (expense) for the indicated periods is comprised of the following:

	For the Year Ended December 31, 2014	2013	2012
	(In thousands)		
Current taxes:			
Federal	$	$	$
State	22	(1,619)	178
Deferred taxes:			
Federal	(88,994)		
State	(11,999)		(285)
Total income tax benefit (expense)	$ (100,971)	$ (1,619)	$ (107)

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The actual income tax benefit (expense) differs from the expected income tax benefit (provision) as computed by applying the federal statutory corporate tax rate of 35% for each period indicated as follows:

	For the Year Ended December 31, 2014	2013	2012
Expected tax benefit (expense)	$ 187,282	$ (53,533)	$ (9,486)
State income tax expense, net of federal benefit	(9,660)	(1,619)	(107)
Pass-through entities (1)	49,989	53,533	9,486
Stock compensation (2)	(330,024)		
Other	1,442		
Total income tax benefit (expense)	$ (100,971)	$ (1,619)	$ (107)

(1) MEMP, a publicly traded partnership with qualifying income, is a pass-through entity for federal income tax purposes. In addition, our predecessor was also a pass-through entity for federal income tax purposes.
(2) As discussed in Note 12, the compensation expense associated with the incentive units of WildHorse Resources and MRD Holdco created a nondeductible permanent difference for income tax purposes.

The components of net deferred income tax assets and (liabilities) recognized were as follows:

	December 31, 2014	2013
	(In thousands)	
Deferred current income tax assets:		
Unrealized hedging transactions	$ 109	$ 37
Accrued liabilities		5
Other	342	(42)
Deferred current income tax assets:	$ 451	$
Deferred current income tax liabilities:		
Unrealized hedging transactions	$ (52,328)	
Other	(52)	(382)
Deferred current income tax liabilities:	$ (52,380)	$ (382)
Deferred noncurrent income tax assets:		
Net operating loss carryforward	$ 28,043	$ 2,350

Asset retirement obligation	5,757	971
Other	3,224	1
Net deferred tax valuation allowance	(2,634)	(2,896)
Deferred noncurrent income tax assets:	$ 34,390	$ 426
Deferred noncurrent income tax liabilities:		
Property, plant and equipment	$ (80,198)	$ (3,318)
Unrealized hedging transactions	(48,929)	(275)
Other	(280)	61
Deferred noncurrent income tax liabilities:	$ (129,407)	$ (3,532)
Net current deferred income tax assets (liabilities)	$ (51,929)	$ (382)
Net noncurrent deferred income tax assets (liabilities)	$ (95,017)	$ (3,106)

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We must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable based on its technical merits. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company has no unrecognized tax benefits for the years ended December 31, 2014, 2013 or 2012.

Generally, the Company s income tax years 2011 through 2014 remain open and subject to examination by Federal tax authorities or state tax authorities where the Company conducts operations. In certain jurisdictions the Company operates through more than one legal entity, each of which may have different open years subject to examination.

The Company recognizes interest and penalties accrued to unrecognized benefits in Other income (expense) in its consolidated statements of operations. For the years ended December 31, 2014, 2013 and 2012 the Company recognized no interest and penalties.

As of December 31, 2014, the Company has available, to reduce future taxable income, a United States net operating loss carryforwards (NOLs) of approximately $74.3 million before consideration of any valuation allowance which expires in the years 2027 thru 2035. A portion of these net operating loss carryforwards are subject to the ownership change limitation provisions of Section 382 of the Internal Revenue Code (IRC). The Company also has various net state NOL carryforwards of approximately $65.0 million, before consideration of any valuation allowance with varying lengths of allowable carryforward periods ranging from 10 to 20 years that can be used to offset future state taxable income.

Note 16. Commitments and Contingencies

Litigation & Environmental

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows.

Environmental costs for remediation are accrued when environmental remediation efforts are probable and the costs can be reasonably estimated. Such accruals are based on management s best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals.

The following table presents the activity of our environmental reserves for the periods presented:

	2014	2013	2012
	(In thousands)		
Balance at beginning of period	$ 577	$ 1,469	$ 1,747
Charged to costs and expenses	2,852		193
Payments	(1,337)	(892)	(471)
Balance at end of period	$ 2,092	$ 577	$ 1,469

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At December 31, 2014 and 2013, $2.1 million and $0.6 million, respectively, of our environmental reserves were classified as current liabilities in accrued liabilities.

Sinking Fund Trust Agreement

REO assumed an obligation with a third party to make payments into a sinking fund in connection with its 2009 acquisition of the Beta properties, the purpose of which is to provide funds adequate to decommission the portion of the San Pedro Bay pipeline that lies within State waters and the surface facilities. Under the terms of the agreement, REO, as the operator of the properties, is obligated to make monthly deposits into the sinking fund account in an amount equal to $0.25 per barrel of oil and other liquid hydrocarbon produced from the acquired working interest. Interest earned in the account stays in the account. The obligation to fund ceases when the aggregate value of the account reaches $4.3 million. As of December 31, 2014, the gross account balance included in restricted investments was approximately $2.7 million. REO s maximum remaining obligation net to its 51.75% interest under the terms of the current agreement was $0.8 million at December 31, 2014.

Supplemental Bond for Decommissioning Liabilities Trust Agreement

REO assumed an obligation with the BOEM in connection with its 2009 acquisition of the Beta properties. Under the terms of the agreement dated March 1, 2007, the seller of the Beta properties was obligated to deliver a $90.0 million U.S. Treasury Note into a trust account for the decommissioning of the offshore production facilities. At the time of acquisition, all obligations under this existing agreement had been met.

In January 2010, the BOEM issued a report that revised upward, the estimated cost of decommissioning. In June 2010, REO agreed to make additional quarterly payments to the trust account attributable to its net working interest of approximately $0.6 million beginning on June 30, 2010 until the payments and accrued interest attributable to REO equal $78.7 million by December 31, 2016. The trust account must maintain minimum balances attributable to REO s net working interest as follows (in thousands):

June 30, 2015	$ 72,450
June 30, 2016	$ 76,590
December 31, 2016	$ 78,660

In the event the account balance is less than the contractual amount, the working interest owners must make additional payments. Interest income earned and deposited in the trust account mitigates the likelihood that additional payments will have to be made by the working interest owners. As of December 31, 2014, the maximum remaining obligation net to REO s interest was approximately $8.7 million.

The trust account is held by REO for the benefit of all working interest owners. The following is a summary of the gross held-to-maturity investments held in the trust account less the outside working interest owners share as of December 31, 2014 (in thousands):

Investment	Amortized Cost
U.S. Bank Money Market Cash Equivalent	$ 135,176
Less: Outside working interest owners share	(65,222)
	$ 69,954

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Purchase Commitment Assumed

At December 31, 2014, MEMP had a CO2 purchase commitment with a third party that was assumed in its Wyoming Acquisition. The table below outlines MEMP s purchase commitment under the contract for the remainder of 2014 and annually thereafter (in thousands):

			Payment or Settlement due by Period				
Purchase commitment	**Total**	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**
CO_2 minimum purchase commitment:							
Estimated payment obligation	$ 50,495	$ 9,608	$ 10,179	$ 10,151	$ 6,995	$ 7,060	$ 6,502

Processing Plant Expansions by Third Party Gatherer

In 2012, WildHorse Resources contracted with Regency Field Services LLC (the Gatherer) to expand their Dubach processing plant by up to 70 MMcf per day among other facility and infrastructure improvements. In 2013, WildHorse Resources contracted with the Gatherer to build a new high pressure pipeline from the dedicated area to the Gatherer s Dubberly processing plant in Webster Parish, LA amongst other pipeline and infrastructure improvements. The Gatherer is entitled to receive a payback demand fee from us and other third parties equal to 110% of the infrastructure improvement costs. Effective February 1, 2014, the payback demand fee is equal to the monthly demand quantity (192,950 MMBtu per day) times $0.275 per MMBtu. In addition, for each MMBtu gathered in excess of the demand quantity, we are obligated to pay a payback demand fee of $0.275 per MMBtu. The monthly demand quantity escalated to 249,700 MMBtu per day until payout effective January 1, 2015.

WildHorse Resources minimum commitments to the Gatherer, before other owner contributions, as of December 31, 2014 were as follows (in thousands):

	Dubach	**Dubberly**
2015	$ 13,671	$ 11,393
2016	13,709	11,424
2017	13,671	11,393
2018	12,772	10,643
Total	$ 53,823	$ 44,853

Related Party Agreements

Classic Operating entered into a gas gathering agreement and water disposal agreement with Classic Pipeline.

On March 17, 2014, WildHorse Resources entered into a gas processing agreement with PennTex. See Note 13 for additional information.

Operating Leases

We have leases for offshore Southern California pipeline right-of-way use as well as office space for our corporate headquarters and operating regions. We also lease equipment and incur surface rentals related to our business operations. For the years ended December 31, 2014, 2013, and 2012 we recognized $10.8 million, $8.3 million, and $5.0 million of rent expense, respectively.

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Amounts shown in the following table represent minimum lease payment obligations and sublease rental income under non-cancelable operating leases with a remaining term in excess of one year:

	Payment or Settlement due by Period						
	Total	2015	2016	2017	2018	2019	Thereafter
	(In thousands)						
MRD Segment:							
Operating leases	$ 43,625	$ 6,534	$ 6,607	$ 6,694	$ 6,259	$ 5,960	$ 11,571
Sublease rental income	5,786	1,691	1,579	1,197	814	431	74
MEMP Segment:							
Operating leases	3,665	788	416	205	205	205	1,846

Note 17. Defined Contribution Plans

MRD sponsors a defined contribution plan for the benefit of substantially all employees who have attained 18 years of age. The plan allows eligible employees to make tax-deferred contributions up to 100% of their annual compensation, not to exceed annual limits established by the Internal Revenue Service. MRD makes matching contributions of 100% of employee contributions that does not exceed 6% of compensation. Employees are immediately vested in these matching contributions. This plan became effective on January 1, 2012. The plan received employer contributions of approximately $1.4 million, $0.9 million, and $0.4 million in 2014, 2013, and 2012 respectively.

Effective January 1, 2012, REO assumed sponsorship of a separate defined contribution plan. This plan specifically benefits substantially all those employed by the MRD subsidiary (Beta Operating) that operates and supports the Beta properties that have attained 21 years of age. Eligible employees are permitted to make tax-deferred contributions up to 100% of their annual compensation, not to exceed annual limits established by the Internal Revenue Service. Employer matching contributions of 100% of employee contributions that does not exceed 6% of compensation are made to the plan as well. The employer matching contributions associated with this plan were subject to a three-year graded vesting schedule through February 28, 2012. Effective March 1, 2012, the plan was amended to offer immediate vesting of employer matching contributions. This plan was terminated December 31, 2013. The plan received employer contributions of approximately $0.6 million and $0.5 million in 2013, and 2012 respectively. Approximately $0.3 million associated with this plan are reflected as costs and expenses in the accompanying statements of operations for the each of the years ended December 31, 2013 and 2012, respectively.

WildHorse, Tanos, BlueStone, Classic and Black Diamond also sponsored defined contribution plans for the benefit their eligible employees. Matching employer contributions of approximately $0.2 million, $0.5 million and $0.6 million were made to these other plans in 2014, 2013 and 2012, respectively.

Crown and Stanolind also made matching contributions to defined contribution plans for the benefit of their eligible employees. Matching employer contributions of approximately $0.1 million were made to these plans in both 2013 and 2012. Such contributions to these plans are included in general and administrative expenses in the accompanying combined statements of operations.

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Note 18. Quarterly Financial Information (Unaudited)

The following tables present selected quarterly financial data for the periods indicated. Earnings per share are computed independently for each of the quarters presented and the sum of the quarterly earnings per share may not necessarily equal the total for the year. As discussed in Note 4 and Note 12, we recorded oil and natural gas property impairments and incentive unit compensation expense, respectively, during 2014, which impacted the comparability between the periods presented below.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
For the Year Ended December 31, 2014				
Revenues	$ 190,828	$ 236,564	$ 245,493	$ 226,460
Operating income (loss)	10,605	(993,256)	174,201	444,776
Net income (loss)	(23,516)	(1,053,443)	112,037	328,859
Net income (loss) attributable to noncontrolling interest	(31,888)	(105,094)	102,109	161,661
Net income (loss) attributable to Memorial Resource Development Corp.	8,372	(948,349)	9,928	167,198
Net income (loss) allocated to members	6,947	13,358		
Net income (loss) allocated to previous owners	1,425			
Net income (loss) available to common stockholders	n/a	(961,707)	9,928	167,198
Basic earnings per share	n/a	(5.00)	0.05	0.87
Diluted earnings per share	n/a	(5.00)	0.05	0.87

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
For the Year Ended December 31, 2013				
Revenues	$ 122,181	$ 147,045	$ 153,515	$ 152,282
Operating income (loss)	9,521	90,327	117,797	4,411
Net income (loss)	180	78,158	95,962	(22,968)
Net income (loss) attributable to noncontrolling interest	(4,069)	34,975	11,235	7,689
Net income (loss) attributable to Memorial Resource	4,249	43,183	84,727	(30,657)

Development Corp.				
Net income (loss) allocated to members	2,597	35,278	84,754	(31,917)
Net income (loss) allocated to previous owners	1,652	7,905	(27)	1,260

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Note 19. Supplemental Oil and Gas Information (Unaudited)

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization is as follows at the dates indicated.

	For the Year Ended December 31, 2014	2013	2012
		(In thousands)	
MRD Segment:			
Evaluated oil and natural gas properties	$ 1,590,997	$ 1,226,417	$ 1,052,219
Unevaluated oil and natural gas properties	48,229	46,413	26,589
Accumulated depletion, depreciation, and amortization	(391,145)	(256,629)	(202,581)
Subtotal	$ 1,248,081	$ 1,016,201	$ 876,227
MEMP Segment:			
Evaluated oil and natural gas properties (1)	$ 3,007,214	$ 1,748,438	$ 1,539,642
Support equipment and facilities	185,997	5,910	5,760
Unevaluated oil and natural gas properties			5,004
Accumulated depletion, depreciation, and amortization (1)	(989,103)	(416,617)	(265,710)
Subtotal	$ 2,204,108	$ 1,337,731	$ 1,284,696
Eliminations:			
Accumulated depletion, depreciation, and amortization	$ 46,013	$ 49,884	$
Consolidated:			
Evaluated oil and natural gas properties (1)	$ 4,598,211	$ 2,974,855	$ 2,591,861
Support equipment and facilities	185,997	5,910	5,760
Unevaluated oil and natural gas properties	48,229	46,413	31,593
Accumulated depletion, depreciation, and amortization (1)	(1,334,235)	(623,362)	(468,291)
Total	$ 3,498,202	$ 2,403,816	$ 2,160,923

(1) Amounts do not include costs for SPBPC and related support equipment.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Costs incurred in property acquisition, exploration and development activities were as follows for the periods indicated:

	For the Year Ended December 31, 2014	2013	2012
		(In thousands)	
MRD Segment:			
Property acquisition costs, proved	$ 74,490	$ 56,108	$ 87,857
Property acquisition costs, unproved	25,030	19,975	5,293
Exploration and extension well costs	209,532	13,313	212
Development	208,459	210,440	135,951
Subtotal	$ 517,511	$ 299,836	$ 229,313
MEMP Segment:			
Property acquisition costs, proved	$ 983,076	$ 37,786	$ 278,246
Exploration and extension well costs			42,430
Development (1)	279,318	145,830	62,472
Subtotal	$ 1,262,394	$ 183,616	$ 383,148
Consolidated:			
Property acquisition costs, proved	$ 1,057,566	$ 93,894	$ 366,103
Property acquisition costs, unproved	25,030	19,975	5,293
Exploration and extension well costs	209,532	13,313	42,642
Development (1)	487,777	356,270	198,423
Total	$ 1,779,905	$ 483,452	$ 612,461

(1) Amounts do not include costs for SPBPC and related support equipment.

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

As required by the FASB and SEC, the standardized measure of discounted future net cash flows presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. We do not believe the standardized measure provides a reliable estimate of the Company s expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

We engaged NSAI and MEMP engaged NSAI and Ryder Scott to audit our internally prepared reserves estimates for all of our estimated proved reserves (by volume) at December 31, 2014. All proved reserves are located in the United States and all prices are held constant in accordance with SEC rules.

The weighted-average benchmark product prices used for valuing the reserves are based upon the average of the first-day-of-the-month price for each month within the period January through December of each year presented:

	2014	2013	2012
Oil ($/Bbl)			
West Texas Intermediate (1)	$ 91.48	$ 93.42	$ 91.33
NGL ($/Bbl)			
West Texas Intermediate (1)	$ 91.48	$ 93.42	$ 91.75
Natural Gas ($/Mmbtu)			
Henry Hub (2)	$ 4.35	$ 3.67	$ 2.75

(1) The unweighted average West Texas Intermediate price was adjusted by lease for quality, transportation fees, and a regional price differential.
(2) The unweighted average Henry Hub price was adjusted by lease for energy content, compression charges, transportation fees, and regional price differentials.

MRD Segment

The following tables set forth estimates of the net reserves as of December 31, 2014, 2013, and 2012 respectively:

	For the Year Ended December 31, 2014			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of the year	11,311	802,254	42,576	1,125,577
Extensions and discoveries	1,825	183,527	9,876	253,730

Purchase of minerals in place	269	22,186	1,247	31,283
Production	(951)	(63,801)	(2,220)	(82,816)
Sales of minerals in place	(623)	(10,815)	(950)	(20,253)
Revision of previous estimates	772	247,578	12,060	324,558
End of year	12,603	1,180,929	62,589	1,632,079
Proved developed reserves:				
Beginning of year	3,402	263,797	13,904	367,641
End of year	3,905	392,181	19,924	535,151
Proved undeveloped reserves:				
Beginning of year	7,909	538,457	28,672	757,936
End of year	8,698	788,748	42,665	1,096,928

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NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

	For the Year Ended December 31, 2013			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of the year	11,953	739,378	41,466	1,059,895
Extensions and discoveries	1,794	149,974	8,319	210,652
Purchase of minerals in place	211	31,815	1,017	39,183
Production	(665)	(34,092)	(1,457)	(46,819)
Sales of minerals in place	(599)	(14,137)	(1,573)	(27,169)
Revision of previous estimates	(1,383)	(70,684)	(5,196)	(110,165)
End of year (1)	11,311	802,254	42,576	1,125,577
Proved developed reserves:				
Beginning of year	3,082	245,449	12,321	337,869
End of year	3,402	263,797	13,904	367,641
Proved undeveloped reserves:				
Beginning of year	8,871	493,929	29,145	722,026
End of year	7,909	538,457	28,672	757,936

(1) Includes reserves of 41,077 MMcfe attributable to noncontrolling interests and the MRD Segment previous owners.

	For the Year Ended December 31, 2012			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of the year	10,834	929,335	53,031	1,312,533
Extensions and discoveries	689	42,019	2,778	62,819
Purchase of minerals in place	1,100	28,115	1,879	45,987
Production	(369)	(24,131)	(898)	(31,731)
Sales of minerals in place	(4)	(728)		(752)
Revision of previous estimates	(297)	(235,232)	(15,324)	(328,961)
End of year (1)	11,953	739,378	41,466	1,059,895
Proved developed reserves:				
Beginning of year	2,107	191,557	7,644	250,073
End of year	3,082	245,449	12,321	337,869
Proved undeveloped reserves:				

Beginning of year	8,727	737,778	45,387	1,062,460
End of year	8,871	493,929	29,145	722,026

(1) Includes reserves of 67,135 MMcfe attributable to noncontrolling interests and the MRD Segment previous owners.

Noteworthy amounts included in the categories of proved reserve changes in the above tables include:

MRD had upward revisions of 324.6 Bcfe primarily due to well performance in East Texas and North Louisiana. Additionally, there was an increase of 253.7 Bcfe from extensions, primarily due to the redevelopment program in the Terryville Complex. MRD also acquired 31.3 Bcfe from multiple acquisitions already inside the Terryville Complex. Proved undeveloped reserves increased during the year primarily due to the development of unproved locations in 2014 and revisions to our forecasts for East Texas properties, which give effect for well performance using longer lateral lengths.

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148.6 Bcfe of the increase in reserves for the year end December 31, 2013, through the category extensions and discoveries, was due to the horizontal redevelopment drilling program in the Terryville Complex.

WildHorse acquired 43.5 Bcfe in multiple acquisitions during the year ended December 31, 2012, the largest being the Undisclosed Seller Acquisition. Downward revisions of previous estimates for estimated natural gas proved reserves was primarily the result of a decrease in natural gas prices.

See Note 3 for additional information on acquisitions and divestitures.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

The standardized measure of discounted future net cash flows is as follows:

	For the Year Ended December 31,		
	2014	2013	2012
		(In thousands)	
Future cash inflows	$ 8,313,329	$ 5,722,848	$ 4,921,192
Future production costs	(1,325,573)	(1,587,374)	(1,255,289)
Future development costs	(1,443,612)	(1,352,945)	(1,060,777)
Future income tax expense (1)	(1,789,031)		
Future net cash flows for estimated timing of cash flows	3,755,113	2,782,529	2,605,126
10% annual discount for estimated timing of cash flows	(1,792,579)	(1,313,577)	(1,284,531)
Standardized measure of discounted future net cash flows (2)	$ 1,962,534	$ 1,468,952	$ 1,320,595

(1) Our predecessor was a pass through entity and was subject to the Texas margin tax which has a maximum effective rate of 0.7% of gross income apportioned to Texas. Due to immateriality, we have excluded the impact of this tax for the years ended December 31, 2013 and 2012.

(2) Includes $63,422 and $78,518 attributable to both noncontrolling interests and the MRD Segment previous owners for the years ended December 31, 2013 and 2012, respectively.

MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2014:

	For the Year Ended December 31,		
	2014	2013	2012
		(In thousands)	
Beginning of year	$ 1,468,952	$ 1,320,595	$ 1,386,071
Sale of oil and natural gas produced, net of production costs	(363,723)	(196,444)	(107,316)
Purchase of minerals in place	69,282	51,177	98,384
Sale of minerals in place	(47,791)	(54,091)	
Extensions and discoveries	653,186	301,004	127,994
Changes in income taxes, net	(1,058,814)		
Changes in prices and costs	365,030	(11,336)	(402,202)
Previously estimated development costs incurred	256,605	87,297	64,390
Net changes in future development costs	(126,598)	57,353	(67,331)
Revisions of previous quantities	828,296	(186,804)	(176,788)
Accretion of discount	146,896	128,544	138,607
Change in production rates and other	(228,787)	(28,343)	258,786
End of year	$ 1,962,534	$ 1,468,952	$ 1,320,595

MEMP Segment

The following tables set forth estimates of the net reserves as of December 31, 2014, 2013, and 2012 respectively:

	For the Year Ended December 31, 2014			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of the year	39,149	607,139	28,846	1,015,105
Extensions and discoveries	849	12,723	711	22,085
Purchase of minerals in place	69,095	13,036	22,351	561,713
Production	(3,092)	(41,494)	(2,143)	(72,902)
Revision of previous estimates	(6,431)	(31,777)	(287)	(72,090)

End of year (1)	99,570	559,627	49,478	1,453,911
Proved developed reserves:				
Beginning of year	22,265	387,548	15,959	616,893
End of year	54,526	380,397	35,539	920,783
Proved undeveloped reserves:				
Beginning of year	16,884	219,591	12,887	398,212
End of year	45,044	179,230	13,939	533,128

(1) MRD Segment s share of these reserves is 1,454 MMcfe.

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NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

	For the Year Ended December 31, 2013			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of the year	39,089	604,440	29,352	1,015,095
Extensions and discoveries	5,655	40,770	1,747	85,180
Purchase of minerals in place	119	16,294	258	18,554
Production	(1,764)	(35,924)	(1,632)	(56,303)
Revision of previous estimates	(3,950)	(18,441)	(879)	(47,421)
End of year (1)	39,149	607,139	28,846	1,015,105
Proved developed reserves:				
Beginning of year	24,515	376,932	15,947	619,704
End of year	22,265	387,548	15,959	616,893
Proved undeveloped reserves:				
Beginning of year	14,574	227,508	13,405	395,391
End of year	16,884	219,591	12,887	398,212

(1) MRD Segment s share of these reserves is 89,837 MMcfe.

	For the Year Ended December 31, 2012			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of the year	27,150	579,751	15,045	832,913
Extensions and discoveries	7,501	19,869	1,053	71,192
Purchase of minerals in place	11,336	113,617	7,095	224,202
Production	(1,519)	(29,744)	(745)	(43,329)
Sales of minerals in place	(4,214)	(4,214)		(29,499)
Revision of previous estimates	(1,165)	(74,839)	6,904	(40,384)
End of year (1)	39,089	604,440	29,352	1,015,095
Proved developed reserves:				
Beginning of year	19,332	413,431	10,015	589,504
End of year	24,515	376,932	15,947	619,704
Proved undeveloped reserves:				
Beginning of year	7,818	166,320	5,030	243,409
End of year	14,574	227,508	13,405	395,391

(1) MRD Segment s share of these reserves is 476,550 MMcfe.

Noteworthy amounts included in the categories of proved reserve changes in the above tables include:

MEMP acquired 561.7 Bcfe in multiple acquisitions during the year ended December 31, 2014, the largest being the Wyoming Acquisition of 497.2 Bcfe. MEMP also acquired 45.0 Bcfe from the Eagle Ford Acquisition. Downward revision of natural gas for the year ended December 31, 2014 was primarily due to updated well performance data in certain East Texas fields. Proved undeveloped reserves increased during the year ended December 31, 2014 primarily due to the Wyoming Acquisition.

MEMP acquired 224.2 Bcfe in multiple acquisitions during the year ended December 31, 2012, the largest being the Goodrich Acquisition of 148.9 Bcfe. Stanolind acquired 43.6 Bcfe through multiple

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

acquisitions, the largest being the Menemsha Acquisition of 23.9 Bcfe. During the year ended December 31, 2012, Propel divested 19.0 Bcfe of offshore Louisiana oil and gas properties to an NGP controlled entity. See Note 3 for additional information on acquisitions and divestitures.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

The standardized measure of discounted future net cash flows is as follows:

	For the Year Ended December 31,		
	2014	2013	2012
		(In thousands)	
Future cash inflows	$ 13,191,866	$ 6,892,150	$ 6,511,776
Future production costs	(4,516,077)	(2,719,024)	(2,258,554)
Future development costs	(1,222,221)	(685,858)	(620,944)
Future net cash flows for estimated timing of cash flows (1)	7,453,568	3,487,268	3,632,278
10% annual discount for estimated timing of cash flows	(4,693,960)	(1,879,156)	(2,042,362)
Standardized measure of discounted future net cash flows (2)	$ 2,759,608	$ 1,608,112	$ 1,589,916

(1) MEMP is subject to the Texas margin tax which has a maximum effective rate of 0.7% of gross income apportioned to Texas. Due to immateriality we have excluded the impact of this tax for the years ended December 31, 2014, 2013 and 2012.

(2) MRD Segment s share of the standardized measure of discounted future net cash flows was $2,760, $142,318 and $554,981 for the years ended December 31, 2014, 2013 and 2012, respectively.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2014:

	For the Year Ended December 31,		
	2014	2013	2012
		(In thousands)	
Beginning of year	$ 1,608,112	$ 1,589,916	$ 1,499,414
Sale of oil and natural gas produced, net of production costs	(323,994)	(234,520)	(160,023)
Purchase of minerals in place	1,489,477	23,160	375,953
Sale of minerals in place			(154,963)
Extensions and discoveries	44,745	136,423	265,108
Changes in income taxes, net			1,947
Changes in prices and costs	(168,500)	(74,395)	(331,760)
Previously estimated development costs incurred	223,861	174,490	66,360
Net changes in future development costs	(74,579)	(74,867)	(1,140)
Revisions of previous quantities	(163,207)	(141,122)	(90,587)
Accretion of discount	160,811	158,991	150,136
Change in production rates and other	(37,118)	50,036	(30,529)
End of year	$ 2,759,608	$ 1,608,112	$ 1,589,916

Note 20. Subsequent Events

Termination of WHR Management Company Service Agreement

For additional information, see Note 13.

2015 Repurchases of MRD Common Stock and MEMP Common Units

For additional information, see Note 9.

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Independent Auditors Report

The Members

Merit Energy Company, LLC:

We have audited the accompanying statements of revenues and direct operating expenses of Merit Energy Company s oil and gas properties under contract for purchase by Memorial Production Partners LP (the Properties) for each of the years in the three-year period ended December 31, 2013.

Management s Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity s preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity s internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly in all material respects, the revenues and direct operating expenses of Merit Energy Company s oil and gas properties under contract for purchase by Memorial Production Partners LP for each of the years in the three-year period ended December 31, 2013, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Dallas, TX

May 30, 2014

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STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

(In thousands)

	Six Months Ended June 30,		Year Ended December 31,		
	2014	2013	2013	2012	2011
	(unaudited)				
Revenues:					
Oil Sales	$ 76,836	$ 73,914	$ 156,981	$ 164,124	$ 172,828
NGL Sales	14,363	14,758	29,440	30,363	33,101
	91,199	88,672	186,421	194,487	205,929
Direct Operating Expenses:					
Lease Operating Expenses	24,608	25,488	53,104	53,250	52,010
Production and Ad Valorem Taxes	11,943	11,625	26,810	23,757	25,244
	36,551	37,113	79,914	77,007	77,254
Excess of Revenues over Direct Operating Expenses	$ 54,648	$ 51,559	$ 106,507	$ 117,480	$ 128,675

See accompanying Notes to Statements of Revenues and Direct Operating Expenses

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NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

SIX MONTHS ENDED JUNE 30, 2014 AND 2013 (UNAUDITED)

AND THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011

NOTE 1 BASIS OF PRESENTATION

On May 5, 2014, Memorial Production Partners LP (Memorial) entered into a Purchase and Sale agreement (PSA) with Merit Energy Company and certain of its affiliates (Merit Energy) to purchase oil and gas properties and related facilities located in the Lost Soldier and Wertz fields in Wyoming as further defined in the PSA (the Properties) for approximately $935 million, subject to normal closing adjustments, with an effective date of April 1, 2014. The accompanying statements of revenues and direct operating expenses relate only to the Properties.

Historical financial statements prepared in accordance with accounting principles generally accepted in the United States of America have never been prepared for the Properties. During the periods presented, the Properties were not accounted for or operated as a consolidated entity or as a separate division by Merit Energy. The accompanying statements of revenues and direct operating expenses related to the Properties were prepared from the historical accounting records of Merit Energy.

Certain indirect expenses, as further described in Note 4, were not allocated to the Properties and have been excluded from the accompanying statements. Any attempt to allocate these expenses would require significant and judgmental allocations, which would be arbitrary and may not be indicative of the performance of the properties on a stand-alone basis.

These statements of revenues and direct operating expenses do not represent a complete set of financial statements reflecting the financial position, results of operations, stakeholder s equity and cash flows of the Properties and are not necessarily indicative of the results of operations for the Properties going forward.

The accompanying statements of revenues and direct operating expenses for the six months ended June 30, 2014 and 2013 are unaudited but, in the opinion of management, include all adjustments (consisting of normal recurring adjustments) that are necessary for a fair presentation of the revenues and direct operating expenses of the Properties for those periods.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Revenue Recognition

Merit Energy utilizes the sales method of accounting for oil and natural gas liquids revenues whereby revenues, net of royalties, are recognized based on the actual volumes of oil and natural gas liquids production sold to purchasers. The amount of natural gas liquids sold may differ from the amount to which Merit Energy is entitled based on its revenue interests in the properties.

Direct Operating Expenses

Direct operating expenses, which are recognized on an accrual basis, relate to the direct expenses of operating the Properties. The direct operating expenses include lease operating, ad valorem tax and production tax expense. Lease operating expenses include lifting costs, well repair expenses, surface repair expenses, well workover costs and other field expenses. Lease operating expenses also include expenses directly associated with support personnel, support services, equipment and facilities directly related to oil and natural gas production activities.

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NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

SIX MONTHS ENDED JUNE 30, 2014 AND 2013 (UNAUDITED)

AND THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011

NOTE 3 CONTINGENCIES

The activities of the Properties are subject to potential claims and litigation in the normal course of operations. Merit Energy management does not believe that any liability resulting from any pending or threatened litigation will have a material adverse effect on the operations or financial results of the Properties.

NOTE 4 EXCLUDED EXPENSES

The Properties are part of a much larger enterprise prior to their sale by Merit Energy to Memorial. Indirect general and administrative expenses, interest, income taxes, and other indirect expenses were not allocated to the Properties and have been excluded from the accompanying statements. In addition, any allocation of such indirect expenses may not be indicative of costs which would have been incurred by the Properties on a stand-alone basis.

Depreciation, depletion, and amortization have been excluded from the accompanying statements of revenues and direct operating expenses as such amounts would not be indicative of the depletion calculated on the Properties on a stand-alone basis.

NOTE 5 SUPPLEMENTARY OIL AND GAS INFORMATION (UNAUDITED)

Estimated Net Quantities of Oil and Natural Gas Reserves

The estimates of Proved Oil and Gas Reserves as of December 31, 2013, 2012, 2011 and 2010 were prepared for Merit Energy utilizing year-end estimates of reserve quantities provided by third-party independent petroleum engineering consultants. The estimated proved net recoverable reserves presented below include only those quantities that were expected to be commercially recoverable at the SEC applicable prices and costs for each year under the then existing regulatory practices and with conventional equipment and operating methods. Proved Developed Reserves represent only those reserves estimated to be recovered through existing wells. Proved Undeveloped Reserves include those reserves that may be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure for recompletion or secondary recovery operation is required. All of the Properties Proved Reserves set forth herein are located in Wyoming. The estimate of reserves, and the standardized measure of discounted future net cash flows shown below reflect Merit Energy s development plan for the Properties rather than Memorial s development plan for those Properties.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of our oil and natural gas properties. Estimates of fair value should also consider unproved reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is subjective and imprecise.

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NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

SIX MONTHS ENDED JUNE 30, 2014 AND 2013 (UNAUDITED)

AND THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011

The following table sets forth estimates of the proved oil and natural gas liquids reserves (net of royalty interests) for the Properties and changes therein, for the periods indicated. The Properties do not contain any natural gas reserves.

	Oil (BBLS)	NGLs (BBLS)
Proved Reserves:		
Balance at December 31, 2010	30,000,203	4,930,909
Production	(1,914,904)	(400,732)
Revisions	3,513,342	351,376
Balance at December 31, 2011	31,598,641	4,881,553
Production	(1,851,220)	(401,615)
Revisions	169,319	416,981
Balance at December 31, 2012	29,916,740	4,896,919
Production	(1,691,073)	(390,554)
Revisions	349,622	72,830
Balance at December 31, 2013	28,575,289	4,579,195

	Oil (BBLS)	NGLs (BBLS)
Proved Developed Reserves:		
Balance at December 31, 2011	28,508,789	4,881,553
Balance at December 31, 2012	27,684,578	4,896,919
Balance at December 31, 2013	26,839,275	4,579,195

Standardized Measure of Discounted Future Net Cash Flows

We have summarized the Standardized Measure related to our proved oil and natural gas liquids reserves. We have based the following summary on a valuation of Proved Reserves using discounted cash flows based on SEC pricing applicable for each year, costs and economic conditions and a 10% discount rate. The additions to Proved Reserves from the purchase of reserves in place and new discoveries and extensions could vary significantly from year to year;

additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, you should not view the information presented below as an estimate of the fair value of our oil and natural gas properties, nor should you consider the information indicative of any trends.

Standardized Measure of Oil and Gas

	December 31,		
in thousands	**2013**	**2012**	**2011**
Future Cash Inflows	$ 2,977,811	$ 3,058,631	$ 3,264,063
Future Production Costs	(1,266,229)	(1,384,561)	(1,449,956)
Future Development Costs	(76,400)	(92,700)	(90,300)
Future Net Cash Flows	1,635,182	1,581,370	1,723,807
Discount of 10% per annum	(741,493)	(758,071)	(850,438)
Standardized Measure of Discounted Future Net Cash Flows	$ 893,689	$ 823,299	$ 873,369

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NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

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AND THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011

During recent years, prices paid for oil and natural gas have fluctuated significantly. Estimated discounted future net cash flows in the table above for December 31, 2013, 2012 and 2011 were computed using NYMEX prices of $96.90, $94.68, and $95.84 per barrel of oil, and $3.67, $2.76, and $4.15 per MMBTU of natural gas, respectively.

The following table sets forth the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas liquids reserves for the period indicated.

Changes in Standardized Measure

	(in thousands)
Balance at December 31, 2010	$ 628,027
Sales of oil and natural gas liquids produced, net	(128,674)
Net changes in prices and production costs	156,678
Net changes in future development costs	(26,755)
Revisions of previous quantity estimates	97,372
Previously estimated development costs incurred	28,458
Accretion of discount	93,083
Changes in timing and other	25,180
Balance at December 31, 2011	$ 873,369
Sales of oil and natural gas liquids produced, net	(117,480)
Net changes in prices and production costs	(29,259)
Net changes in future development costs	(22,330)
Revisions of previous quantity estimates	14,678
Previously estimated development costs incurred	40,490
Accretion of discount	106,533
Changes in timing and other	(42,702)
Balance at December 31, 2012	$ 823,299
Sales of oil and natural gas liquids produced, net	(106,519)
Net changes in prices and production costs	63,290
Net changes in future development costs	(7,957)
Revisions of previous quantity estimates	11,919
Previously estimated development costs incurred	30,858

Accretion of discount		78,857
Changes in timing and other		(58)
Balance at December 31, 2013	$	893,689

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APPENDIX A:

LETTER OF TRANSMITTAL

TO TENDER

OLD 5.875% SENIOR NOTES DUE 2022

OF

MEMORIAL RESOURCE DEVELOPMENT CORP.

PURSUANT TO THE EXCHANGE OFFER AND PROSPECTUS

DATED MAY 4, 2015

THE EXCHANGE OFFER AND WITHDRAWAL RIGHTS WILL EXPIRE AT 5:00 P.M., NEW YORK CITY TIME, ON JUNE 2, 2015 (THE EXPIRATION DATE), UNLESS THE EXCHANGE OFFER IS EXTENDED BY THE ISSUER.

The Exchange Agent for the Exchange Offer is:

U.S. Bank National Association

Corporate Trust Services

EP-MN-WS2N

60 Livingston Avenue

St. Paul, MN 55107

Attn: Specialized Finance

(651) 466-5129

(651) 466-7372 (fax)

If you wish to exchange old 5.875% Senior Notes due 2022 for an equal aggregate principal amount at maturity of new 5.875% Senior Notes due 2022 pursuant to the exchange offer, you must validly tender (and not validly withdraw) old notes to the exchange agent prior to the expiration date.

The undersigned hereby acknowledges receipt and review of the Prospectus, dated May 4, 2015 (the Prospectus), of Memorial Resource Development Corp. (the Issuer), and this Letter of Transmittal (the Letter of Transmittal), which together describe the Issuer s offer (the Exchange Offer) to exchange its issued and outstanding 5.875% Senior Notes due 2022 (the old notes) for a like principal amount of its 5.875% Senior Notes due 2022 (the new notes) that have been registered under the Securities Act of 1933, as amended (the Securities Act). Capitalized terms used but not defined herein have the respective meaning given to them in the Prospectus.

The Issuer reserves the right, at any time or from time to time, to extend the Exchange Offer at its discretion, in which event the term Expiration Date shall mean the latest date to which the Exchange Offer is extended. The Issuer shall notify the Exchange Agent and each registered holder of the old notes of any extension by oral or written notice prior to 9:00 a.m., New York City time, on the next business day after the previously scheduled Expiration Date.

This Letter of Transmittal is to be used by holders of the old notes. Tender of old notes is to be made according to the Automated Tender Offer Program (ATOP) of The Depository Trust Company (DTC) pursuant to the procedures set forth in the Prospectus under the caption Exchange Offer Procedures for Tendering. DTC participants that are accepting the Exchange Offer must transmit their acceptance to DTC, which will verify the acceptance and execute a book-entry delivery to the Exchange Agent s DTC account. DTC will then send a computer-generated message known as an agent s message to the Exchange Agent for its acceptance. For you to validly tender your old notes in the Exchange Offer, the Exchange Agent must receive, prior to the Expiration Date, an agent s message under the ATOP procedures that confirms that:

DTC has received your instructions to tender your old notes; and

you agree to be bound by the terms of this Letter of Transmittal.

BY USING THE ATOP PROCEDURES TO TENDER OLD NOTES, YOU WILL NOT BE REQUIRED TO DELIVER THIS LETTER OF TRANSMITTAL TO THE EXCHANGE AGENT. HOWEVER, YOU WILL BE BOUND BY ITS TERMS, AND YOU WILL BE DEEMED TO HAVE MADE THE ACKNOWLEDGEMENTS AND THE REPRESENTATIONS AND WARRANTIES IT CONTAINS, JUST AS IF YOU HAD SIGNED IT.

PLEASE READ THE ACCOMPANYING INSTRUCTIONS CAREFULLY.

Ladies and Gentlemen:

1. By tendering old notes in the Exchange Offer, you acknowledge receipt of the Prospectus and this Letter of Transmittal.

2. By tendering old notes in the Exchange Offer, you represent and warrant that you have full authority to tender the old notes described above and will, upon request, execute and deliver any additional documents deemed by the Issuer to be necessary or desirable to complete the tender of old notes.

3. You understand that the tender of the old notes pursuant to all of the procedures set forth in the Prospectus will constitute an agreement between you and the Issuer as to the terms and conditions set forth in the Prospectus.

4. By tendering old notes in the Exchange Offer, you acknowledge that the Exchange Offer is being made in reliance upon interpretations contained in no-action letters issued to third parties by the staff of the Securities and Exchange Commission (the SEC), including Exxon Capital Holdings Corp., SEC No-Action Letter (available May 13, 1988), Morgan Stanley & Co., Inc., SEC No-Action Letter (available June 5, 1991) and Shearman & Sterling, SEC No-Action Letter (available July 2, 1993), that the new notes issued in exchange for the old notes pursuant to the Exchange Offer may be offered for resale, resold and otherwise transferred by holders thereof without compliance with the registration and prospectus delivery provisions of the Securities Act (other than a broker-dealer who purchased old notes exchanged for such new notes directly from the Issuer to resell pursuant to Rule 144A or any other available exemption under the Securities Act, and any such holder that is an affiliate of the Issuer within the meaning of Rule 405 under the Securities Act), provided that such new notes are acquired in the ordinary course of such holders business and such holders are not participating in, and have no arrangement with any other person to participate in, the distribution of such new notes.

5. By tendering old notes in the Exchange Offer, you hereby represent and warrant that:

(a) the new notes acquired pursuant to the Exchange Offer are being obtained in the ordinary course of your business, whether or not you are the holder;

(b) you are not participating, or intend to participate, in the distribution of the new notes;

(c) you have no arrangement or understanding with any person to participate in the distribution of old notes or new notes within the meaning of the Securities Act;

(d) you are not an affiliate, as such term is defined under Rule 405 promulgated under the Securities Act, of the Issuer; and

(e) if you are a broker-dealer, you will receive the new notes for your own account in exchange for old notes that were acquired as a result of market-making activities or other trading activities, and you acknowledge that 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.

You may, if you are unable to make all of the representations and warranties contained in Item 5 above and as otherwise permitted in the Registration Rights Agreement (as defined below), elect to have your old notes registered in the shelf registration statement described in the registration rights agreement, dated as of July 10, 2014, by and among the Issuer, the initial guarantors party thereto and Citigroup Global Markets Inc., as representative of the Initial Purchasers (as defined therein) (the Registration Rights Agreement). Such election may be made by notifying the Issuer in writing at 500 Dallas Street, Suite 1800, Houston, Texas 77002; Attn: Kyle N. Roane, Senior Vice President, General Counsel and Corporate Secretary. By making such election, you agree, as a holder of old notes participating in a shelf registration, to indemnify and hold harmless the Issuer, the guarantors, and their respective directors, each of the officers of the Issuer and the guarantors who signs such shelf registration statement, and each person who controls the Issuer or any of the guarantors, within the meaning of either the Securities Act or the Securities Exchange Act of 1934, as amended (the Exchange Act), and the respective officers, directors, partners, employees, representatives and agents of each such person, from and against any and all losses, claims, damages or liabilities caused by any untrue statement or alleged untrue statement of a material fact contained in any shelf registration statement or prospectus, or in any supplement thereto or amendment thereof, or caused by the omission or alleged omission to state therein a material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading; but only with respect to information relating to the undersigned furnished in writing by or on behalf of the undersigned expressly for use in a shelf registration statement, a prospectus or any amendments or supplements thereto. Any such indemnification shall be governed by the terms and subject to the conditions set forth in the Registration Rights Agreement, including, without limitation, the provisions regarding notice, retention of counsel, contribution and payment of expenses set forth therein. The above summary of the indemnification provisions of the Registration Rights Agreement is not intended to be exhaustive and is qualified in its entirety by the Registration Rights Agreement.

6. If you are a broker-dealer that will receive new notes for your own account in exchange for old notes that were acquired as a result of market-making activities or other trading activities, you acknowledge, by tendering old notes in the Exchange Offer, that you will deliver a prospectus in connection with any resale of such new notes; however, by so acknowledging and by delivering a prospectus, you will not be deemed to admit that you are an underwriter within the meaning of the Securities Act.

7. If you are a broker-dealer and old notes held for your own account were not acquired as a result of market-making or other trading activities, such old notes cannot be exchanged pursuant to the Exchange Offer.

8. Any of your obligations hereunder shall be binding upon your successors, assigns, executors, administrators, trustees in bankruptcy, and legal and personal representatives.

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INSTRUCTIONS

FORMING PART OF THE TERMS AND CONDITIONS OF THE EXCHANGE OFFER

1. Book-Entry Confirmations.
Any confirmation of a book-entry transfer to the Exchange Agent s account at DTC of old notes tendered by book-entry transfer (a Book-Entry Confirmation), as well as an agent s message and any other documents required by this Letter of Transmittal, must be received by the Exchange Agent at its address set forth herein prior to 5:00 p.m., New York City time, on the Expiration Date.

2. Partial Tenders.
Tenders of old notes will be accepted only in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof. The entire principal amount of old notes delivered to the Exchange Agent will be deemed to have been tendered unless otherwise communicated to the Exchange Agent. If the entire principal amount of all old notes is not tendered, then old notes for the principal amount of old notes not tendered and new notes issued in exchange for any old notes accepted will be delivered to the holder via the facilities of DTC promptly after the old notes are accepted for exchange.

3. Validity of Tenders.
All questions as to the validity, form, eligibility (including time of receipt), acceptance and withdrawal of tendered old notes will be determined by the Issuer, in its sole discretion, which determination will be final and binding. The Issuer reserves the absolute right to reject any or all tenders not in proper form or the acceptance for exchange of which may, in the opinion of counsel for the Issuer, be unlawful. The Issuer also reserves the absolute right to waive any of the conditions of the Exchange Offer or any defect or irregularity in the tender of any old notes. The Issuer s interpretation of the terms and conditions of the Exchange Offer (including the instructions on the Letter of Transmittal) will be final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of old notes must be cured within such time as the Issuer shall determine. Although the Issuer intends to notify holders of defects or irregularities with respect to tenders of old notes, neither the Issuer, the Exchange Agent nor any other person shall be under any duty to give notification of any defects or irregularities in tenders or incur any liability for failure to give such notification. Tenders of old notes will not be deemed to have been 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 by the Exchange Agent to the tendering holders, unless otherwise provided in the Letter of Transmittal, promptly following the Expiration Date.

4. Waiver of Conditions
The Issuer reserves the absolute right to waive, in whole or part, up to the expiration of the Exchange Offer, any of the conditions to the Exchange Offer set forth in the Prospectus or in this Letter of Transmittal.

5. No Conditional Tender

No alternative, conditional, irregular or contingent tender of old notes will be accepted.

6. Requests for Assistance or Additional Copies

Requests for assistance or for additional copies of the Prospectus or this Letter of Transmittal may be directed to the Exchange Agent at the address or telephone number set forth on the cover page of this Letter of Transmittal. Holders may also contact their broker, dealer, commercial bank, trust company or other nominee for assistance concerning the Exchange Offer.

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7. Withdrawal

Tenders may be withdrawn only pursuant to the limited withdrawal rights set forth in the Prospectus under the caption Exchange Offer Withdrawal of Tenders.

8. No Guarantee of Late Delivery

There is no procedure for guarantee of late delivery in the Exchange Offer.

IMPORTANT: BY USING THE ATOP PROCEDURES TO TENDER OLD NOTES, YOU WILL NOT BE REQUIRED TO DELIVER THIS LETTER OF TRANSMITTAL TO THE EXCHANGE AGENT. HOWEVER, YOU WILL BE BOUND BY ITS TERMS, AND YOU WILL BE DEEMED TO HAVE MADE THE ACKNOWLEDGEMENTS AND THE REPRESENTATIONS AND WARRANTIES IT CONTAINS, JUST AS IF YOU HAD SIGNED IT.

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APPENDIX B:

GLOSSARY OF OIL AND NATURAL GAS TERMS

Analogous Reservoir: Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

Basin: A large depression on the earth s surface in which sediments accumulate.

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

Bcf: One billion cubic feet of natural gas.

Bcfe: One billion cubic feet of natural gas equivalent.

Boe: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

Btu: One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Developed Acreage: The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential: An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Economically Producible: The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For this determination, the value of the products that generate revenue are determined at the terminal point of oil and natural gas producing activities.

Estimated Ultimate Recovery (EUR): Estimated ultimate recovery is the sum of proved reserves remaining as of a given date and cumulative production as of that date.

Exploitation: A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory Well: A well drilled to find and produce oil and natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Field: An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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Gross Acres or Gross Wells: The total acres or wells, as the case may be, in which we have working interest.

ICE: Inter-Continental Exchange.

MBtu/d: One thousand Btu per day.

Mcf: One thousand cubic feet of natural gas.

MMBtu: One million British thermal units.

MMcf: One million cubic feet of natural gas.

MMcfe: One million cubic feet of natural gas equivalent.

Net Acres or Net Wells: Gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

Net Production: Production that is owned by us less royalties and production due others.

Net Revenue Interest: A working interest owner s gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

NGLs: The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

Oil: Oil and condensate.

Operator: The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

Play: A geographic area with hydrocarbon potential.

Possible Reserves: Reserves that are less certain to be recovered than probable reserves.

Probable Reserves: Reserves that are less certain to be recovered than proved reserves but that, together with proved reserves, are as likely as not to be recovered.

Productive Well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

Proved Developed Reserves: Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves: Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration, unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PUDs: Proved Undeveloped Reserves.

Proved Undeveloped Reserves: Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Standardized Measure: The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules, regulations or standards established by the United States Securities and Exchange Commission (SEC) and the Financial Accounting Standards Board (FASB) (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Because we are a corporation, we are subject to federal or state income taxes and thus make provision for federal or state income taxes in the calculation of our standardized measure. Standardized measure does not give effect to derivative transactions.

Realized Price: The cash market price less all expected quality, transportation and demand adjustments.

Recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reliable Technology: Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserve Life: A measure of the productive life of an oil and natural gas property or a group of properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year-end by production volumes. In our calculation of reserve life, production volumes are adjusted, if necessary, to reflect property acquisitions and dispositions.

Reserves: Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir: A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Resources: Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

Spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

Undeveloped Acreage: Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Wellbore: The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

Working Interest: An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

WTI: West Texas Intermediate.

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APPENDIX C

January 16, 2015

Mr. John A. Weinzierl

Memorial Resource Development Corp.

500 Dallas Street, Suite 1800

Houston, Texas 77002

Dear Mr. Weinzierl:

In accordance with your request, we have audited the estimates prepared by Memorial Resource Development Corp. (MRD), as of December 31, 2014, of the proved, probable, and possible reserves and future revenue to the MRD interest in certain oil and gas properties located in Colorado, Louisiana, Texas, and Wyoming. MRD owns its interest in these properties through its subsidiaries MRD Operating LLC; Classic Hydrocarbons, Inc.; and WildHorse Resources, LLC (WHR). It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by MRD (other than those attributable to Memorial Production Partners LP and its subsidiaries). We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, future net revenue, and the present value of such future net revenue, using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves and future revenue have been prepared in accordance with the definitions and regulations of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities   Oil and Gas. We completed our audit on or about the date of this letter. This report has been prepared for MRD   s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth MRD   s estimates of the net reserves and future net revenue, as of December 31, 2014, for the audited properties:

	Net Reserves			Future Net Revenue (M$)	
	Oil	NGL	Gas[1]		Present Worth
Category	(MBBL)	(MBBL)	(MMCF)	Total	at 10%
Proved Developed Producing	3,290.2	18,210.6	358,794.8	1,959,241.4	1,186,884.2
Proved Developed Non-Producing	614.5	1,713.1	33,385.8	192,689.5	102,958.2
Proved Undeveloped	8,698.1	42,665.1	788,748.0	3,392,213.5	1,731,505.7
Total Proved	12,602.8	62,588.9	1,180,928.6	5,544,144.5	3,021,348.1
Probable	8,448.4	40,569.7	610,362.7	2,887,529.8	1,137,039.4
Possible	35,765.0	90,667.9	1,595,661.8	7,559,928.0	2,341,831.3

Totals may not add because of rounding.

(1) Estimates of gas reserves include field fuel usage volumes for the WHR properties.

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The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

When compared on a field-by-field basis, some of the estimates of MRD are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates of MRD s proved, probable, and possible reserves and future revenue shown herein are, in the aggregate, reasonable and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates, cumulatively aggregated through each reserves category, are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by MRD in preparing the December 31, 2014, estimates of reserves and future revenue, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by MRD.

The estimates shown herein are for proved, probable, and possible reserves. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Prices used by MRD are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. For oil and NGL volumes, the average West Texas Intermediate posted price of $91.48 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $4.350 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. For the proved reserves, the average adjusted product prices weighted by production over the remaining lives of the properties are $90.89 per barrel of oil, $37.90 per barrel of NGL, and $4.182 per MCF of gas.

Operating costs used by MRD are based on historical operating expense records. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs for the operated properties are limited to direct lease- and field-level costs and MRD s estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs, per-unit-of-production costs, and workover costs. Capital costs used by MRD are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Operating costs and capital costs are not escalated for inflation. Estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of MRD and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by MRD, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by MRD with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of MRD s overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by MRD, are on file in our office. The technical persons responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Philip S. (Scott) Frost, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1984 and has over 4 years of prior industry experience. William J. Knights, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Philip S. (Scott) Frost

By: /s/ William J. Knights

Philip S. (Scott) Frost, P.E. 88738 Senior Vice President	William J. Knights, P.G. 1532 Vice President
Date Signed: January 16, 2015	Date Signed: January 16, 2015

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APPENDIX D

February 13, 2015

Mr. John A. Weinzierl

Memorial Production Partners LP

500 Dallas Street, Suite 1800

Houston, Texas 77002

Dear Mr. Weinzierl:

In accordance with your request, we have audited the estimates prepared by Memorial Production Partners LP (MEMP), as of December 31, 2014, of the proved reserves and future revenue to the MEMP interest in certain oil and gas properties located in Alabama, Colorado, Louisiana, New Mexico, Texas, and Wyoming. It is our understanding that the proved reserves estimated in this report constitute approximately 30 percent of the proved reserves owned by MEMP. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, future net revenue, and the present value of such future net revenue, using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves and future revenue have been prepared in accordance with the definitions and regulations of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas. We completed our audit on or about the date of this letter. This report has been prepared for MEMP s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth MEMP s estimates of the net reserves and future net revenue, as of December 31, 2014, for the audited properties:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas[(1)] (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	5,347.8	5,215.1	195,356.1	645,434.3	368,930.2
Proved Developed Non-Producing	213.7	1,287.8	32,469.7	89,368.8	33,360.7
Proved Undeveloped	6,074.1	2,620.4	81,787.1	291,702.4	73,654.9
Total Proved	11,635.6	9,123.3	309,612.9	1,026,505.4	475,945.8

Totals may not add because of rounding.

(1) Estimates of gas reserves include field fuel usage volumes for certain properties.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

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When compared on a field-by-field basis, some of the estimates of MEMP are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates of MEMP s proved reserves and future revenue shown herein are, in the aggregate, reasonable and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by MEMP in preparing the December 31, 2014, estimates of reserves and future revenue, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by MEMP.

The estimates shown herein are for proved reserves. MEMP s estimates do not include probable or possible reserves that may exist for these properties, nor do they include any value for undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Prices used by MEMP are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. For oil and NGL volumes, the average West Texas Intermediate posted price of $91.48 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $4.350 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $84.72 per barrel of oil, $29.63 per barrel of NGL, and $3.956 per MCF of gas.

Operating costs used by MEMP are based on historical operating expense records. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs for the operated properties are limited to direct lease- and field-level costs and MEMP s estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs, per-unit-of-production costs, and workover costs. Capital costs used by MEMP are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Operating costs and capital costs are not escalated for inflation. Estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of MEMP and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by MEMP, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

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It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by MEMP with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of MEMP s overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by MEMP, are on file in our office. The technical persons responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Justin S. Hamilton, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 4 years of prior industry experience. David E. Nice, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 13 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Justin S. Hamilton
Justin S. Hamilton, P.E. 104999
Vice President

Date Signed: February 13, 2015

By: /s/ David E. Nice
David E. Nice, P.G. 346
Vice President

Date Signed: February 13, 2015

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APPENDIX E

MEMORIAL PRODUCTION PARTNERS LP

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2014

/s/ Miles R. Palke	/s/ Ali A. Porbandarwala
Miles R. Palke, P.E.	Ali A. Porbandarwala
TBPE License No. 94894	TBPE License No. 107652
Managing Senior Vice President	Senior Petroleum Engineer

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, L.P.

TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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TBPE REGISTERED ENGINEERING FIRM F-1580
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February 13, 2015

Mr. John Williams

Memorial Production Partners LP

500 Dallas Street, Suite 1800

Houston, Texas 77002

Dear Mr. Williams,

At the request of Memorial Production Partners LP (Memorial), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves, future production and discounted future net income as of December 31, 2014 prepared by Memorial s engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on February 13, 2015 and presented herein, was prepared for public disclosure by Memorial in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves and income data shown herein represent Memorial s estimated net reserves and income data attributable to the leasehold interests in certain properties owned by Memorial and the portion of those reserves and income data reviewed by Ryder Scott, as of December 31, 2014. The properties reviewed by Ryder Scott incorporate Memorial s reserve determinations and are located in the states of California, Texas and Wyoming.

The properties reviewed by Ryder Scott account for a portion of Memorial s total net proved reserves as of December 31, 2014. Based on the estimates of total net proved reserves prepared by Memorial, the reserves audit conducted by Ryder Scott addresses 87 percent of the total proved developed net liquid hydrocarbon reserves, 40 percent of the total proved developed net gas reserves, 85 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 54 percent of the total proved undeveloped net gas reserves of Memorial. The reserves audit conducted by Ryder Scott addresses 70 percent of the total proved net reserves on a barrel of oil equivalent, BOE basis.

The properties reviewed by Ryder Scott account for a portion of Memorial s total proved discounted future net income using SEC hydrocarbon price parameters as of December 31, 2014. Based on the reserve and income projections prepared by Memorial, the audit conducted by Ryder Scott addresses 79 percent of the discounted future net income at 10 percent of the total proved developed reserves and 91 percent of the discounted future net income at 10 percent of the total proved undeveloped reserves of Memorial.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities.

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Memorial Production Partners LP

February 13, 2015

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Based on our review, including the data, technical processes and interpretations presented by Memorial, it is our opinion that the overall procedures and methodologies utilized by Memorial in preparing their estimates of the proved reserves, future production and discounted future net income as of December 31, 2014 comply with the current SEC regulations and that the overall proved reserves, future production and discounted future net income for the reviewed properties as estimated by Memorial are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves and future net income amounts presented in this report are related to hydrocarbon prices. Memorial has informed us that in the preparation of their reserve and income projections, as of December 31, 2014, they used average prices during the 12-month period prior to the as of date of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves and net income data as estimated by Memorial attributable to Memorial s interest in properties that we reviewed and net income data including those are summarized as follows:

SEC PARAMETERS

Estimated Net Reserves and Income Data

Certain Leasehold Interests of

Memorial Production Partners LP

As of December 31, 2014

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Audited by Ryder Scott				
Net Remaining Reserves				
Oil/Condensate Barrels	41,699,566	7,264,515	38,969,976	87,934,057
Plant Products Barrels	23,495,220	5,540,715	11,318,559	40,354,494
Gas MMCF	144,450	8,121	97,443	250,014
BOE	89,269,714	14,158,794	66,528,978	169,957,486
Income Data (M$)				

Future Gross Revenue	$ 5,148,375	$ 968,904	$ 4,044,900	$ 10,162,179
Deductions	2,151,546	396,612	1,186,959	3,735,117
Future Net Income (FNI)	$ 2,996,829	$ 572,292	$ 2,857,941	$ 6,427,062
Discounted FNI @ 10%	$ 1,325,715	$ 189,711	$ 768,236	$ 2,283,662

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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Memorial Production Partners LP

February 13, 2015

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Not Audited by Ryder Scott				
Net Reserves				
Oil/Condensate Barrels	5,347,801	213,651	6,074,140	11,635,591
Plant Products Barrels	5,215,089	1,287,765	2,620,417	9,123,271
Gas MMCF	195,356	32,470	81,787	309,613
BOE	43,122,248	6,913,028	22,325,742	72,361,018
Income Data (M$)				
Future Gross Revenue	$ 1,299,086	$ 166,780	$ 859,350	$ 2,325,215
Deductions	653,651	77,411	567,647	1,298,710
Future Net Income (FNI)	$ 645,434	$ 89,369	$ 291,702	$ 1,026,505
Discounted FNI @ 10%	$ 368,930	$ 33,361	$ 73,655	$ 475,946
Total Net Reserves				
Oil/Condensate Barrels	47,047,367	7,478,166	45,044,116	99,569,648
Plant Products Barrels	28,710,309	6,828,480	13,938,976	49,477,765
Gas MMCF	339,806	40,591	179,230	559,627
BOE	132,391,962	21,071,822	88,854,720	242,318,504
Income Data (M$)				
Future Gross Revenue	$ 6,447,461	$ 1,135,684	$ 4,904,250	$ 12,487,394
Deductions	2,805,197	474,023	1,754,606	5,033,827
Future Net Income (FNI)	$ 3,642,263	$ 661,661	$ 3,149,643	$ 7,453,567
Discounted FNI @ 10%	$ 1,694,645	$ 223,072	$ 841,891	$ 2,759,608

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an as sold basis expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net remaining reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. BOE means barrels of oil equivalent. In this report, all income data are expressed as thousands of U.S. dollars (M$).

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from

210.4-10(a) entitled Petroleum Reserves Definitions is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled Petroleum Reserves Status Definitions and Guidelines in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe categories.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Memorial s request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward. The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a high degree of confidence that the quantities will be recovered.

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease. Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the quantities actually recovered are much more likely than not to be achieved. The SEC states that probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. The SEC states that possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by Memorial, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 85 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through December 2014, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Memorial and were considered sufficient for the purpose thereof. The remaining 15 percent of the proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

All of the proved developed non-producing and undeveloped reserves that we reviewed were estimated by a combination of methods. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by Memorial for our review were available through December 31, 2014. The data utilized from the analogues in conjunction with well data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

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As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. The economic data used by Memorial were accepted as factual data and we have not conducted an independent verification of the data used by Memorial.

The hydrocarbon prices furnished by Memorial for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the as of date of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2014 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the benchmark prices and price reference used by Memorial for the geographic area reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by Memorial to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as differentials. The differentials used by Memorial were accepted as factual data and we have not conducted an independent verification of the data used by Memorial.

The table below summarizes Memorial s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Memorial s average realized prices. The average realized prices shown in the table below were determined from Memorial s estimate of the total future gross revenue before production taxes for the properties reviewed by us and Memorial s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	Plains Marketing	$91.48/Bbl	$87.01/Bbl

	POSTED WTI (Midland)		
NGLs	Plains Marketing POSTED WTI (Midland)	$91.48/Bbl	$51.67/Bbl
Gas	Henry Hub	$4.35/MMBTU	$3.92/MCF

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The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Memorial s individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserve estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by Memorial are based on the operating expense reports of Memorial and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs furnished by Memorial were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Memorial. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Memorial are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Memorial were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Memorial. The estimated net cost of abandonment after salvage was included by Memorial for properties where abandonment costs net of salvage were significant. Memorial s estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Memorial s plans to develop these reserves as of December 31, 2014. The implementation of Memorial s development plans as presented to us is subject to the approval process adopted by Memorial s management. As the result of our inquiries during the course of our review, Memorial has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Memorial s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Memorial. Additionally, Memorial has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2014, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Memorial were held constant throughout the life of the properties.

Memorial s forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Memorial to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Memorial. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Memorial s estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Memorial s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Memorial owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Memorial for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Memorial are responsible for the preparation of reserve estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Memorial has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Memorial s forecast of future proved production and income, we have relied upon data furnished by Memorial with respect to property interests, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Memorial. The data described herein were accepted as authentic and sufficient for determining the reserves unless, during the course of our examination, a matter of question came to our attention in which case the data were not accepted until all questions were satisfactorily resolved. We consider the factual data furnished to us by Memorial to be appropriate and sufficient for the purpose of our review of Memorial s estimates of reserves and future net income. In summary, we consider the assumptions, data, methods and analytical procedures used by Memorial and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

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Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Memorial, it is our opinion that the overall procedures and methodologies utilized by Memorial in preparing their estimates of the proved reserves, future production and discounted future net income as of December 31, 2014 comply with the current SEC regulations and that the overall proved reserves, future production and discounted future net income for the reviewed properties as estimated by Memorial are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

We were in reasonable agreement with Memorial s estimates of proved reserves, future production and discounted future net income for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Memorial s estimates and our estimates due to a difference in interpretation of data when its reserve estimates were prepared. However not withstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves, future production and discounted future net income owned by Memorial.

Other Properties

Other properties, as used herein, are those properties of Memorial which we did not review. The proved net reserves attributable to the other properties account for 14 percent of the total proved net liquid hydrocarbon reserves and 55 percent of the total proved net gas reserves based on estimates prepared by Memorial as of December 31, 2014. The other properties represent 17 percent of the total proved discounted future net income at 10 percent based on the unescalated pricing policy of the SEC as taken from reserve and income projections prepared by Memorial as of December 31, 2014.

The same technical personnel of Memorial were responsible for the preparation of the reserve estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer s license or a registered or certified professional geoscientist s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

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We are independent petroleum engineers with respect to Memorial. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical persons primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Memorial.

Memorial has certain registration statements filed with the SEC under the 1933 Securities Act. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Memorial of the references to our name as well as to the references to our third party report for Memorial. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Memorial.

We have provided Memorial with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Memorial and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Miles R. Palke
Miles R. Palke, P.E.
TBPE License No. 94894
Managing Senior Vice President **[SEAL]**

/s/ Ali A. Porbandarwala

Ali A. Porbandarwala, P.E.
TBPE License No. 107652
Senior Petroleum Engineer

[SEAL]

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Miles Robert Palke was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Palke, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2010, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies with extensive experience in the Gulf of Mexico and other regions. Before joining Ryder Scott, Mr. Palke served in a number of engineering positions with BHP Billiton, Ryder Scott Company, and ARCO. For more information regarding Mr. Palke s geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Palke earned a Bachelor of Science in Petroleum Engineering from Texas A&M University in College Station TX and a Master of Science in Petroleum Engineering from Stanford University in Palo Alto California. Mr. Palke graduated Magna Cum Laude and with University Honors from Texas A&M University and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Palke fulfills. As part of his 2014 continuing education hours, Mr. Palke attended 10 hours of in-house reserves training and conferences, and 2 hours of industry presentations on related materials such as pressure transient analysis, and reservoir engineering of unconventional resources.

Based on his educational background, professional training and more than 18 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Palke has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers as of February 19, 2007.

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PETROLEUM RESERVES DEFINITIONS

As Adapted From:

RULE 4-10(a) of REGULATION S-X PART 210

UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the Modernization of Oil and Gas Reporting; Final Rule in the Federal Register of National Archives and Records Administration (NARA). The Modernization of Oil and Gas Reporting; Final Rule includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The Modernization of Oil and Gas Reporting; Final Rule , including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the SEC regulations . The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

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PETROLEUM RESERVES DEFINITIONS

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Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

PETROLEUM RESERVES DEFINITIONS

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PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:

RULE 4-10(a) of REGULATION S-X PART 210

UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)

Sponsored and Approved by:

SOCIETY OF PETROLEUM ENGINEERS (SPE)

WORLD PETROLEUM COUNCIL (WPC)

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)

SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate, but which have not started producing;

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PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

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(2) wells which were shut-in for market conditions or pipeline connections; or

(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

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