Memorial Resource Development Corp.
Form 424B4
June 16, 2014
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Filed Pursuant to Rule 424(b)(4)
Registration No. 333-195062

PROSPECTUS

42,800,000 Shares

Memorial Resource Development Corp.

Common Stock

$19.00 per share

This is our initial public offering. We are selling 21,500,000 shares of common stock, and MRD Holdco LLC is selling 21,300,000 shares of our common stock. MRD Holdco LLC has granted the underwriters a 30-day option to purchase up to an additional 6,420,000 shares of common stock. We will not receive any proceeds from the sale of shares by MRD Holdco LLC, including any shares that it may sell pursuant to the underwriters option to purchase additional shares of common stock.

No public market exists for our common stock. We have been approved to list our common stock on the NASDAQ Global Market under the symbol MRD. Following the completion of this offering, we will be a controlled company as defined under the NASDAQ listing rules because the group consisting of affiliates of Natural Gas Partners will beneficially own over 50% of our shares of outstanding common stock. See Principal and Selling Stockholders.

Investing in our common stock involves risks that are described in the Risk Factors section beginning on page 25 of this prospectus.

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 Risk Factors and Summary Emerging Growth Company Status.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

	Per Share	Total
Initial Public Offering Price	$ 19.00	$ 813,200,000
Underwriting Discounts and Commissions(1)	$ 1.06875	$ 45,742,500
Proceeds, Before Expenses, to Us	$ 17.93125	$ 385,521,875
Proceeds, Before Expenses, to MRD Holdco LLC	$ 17.93125	$ 381,935,625

(1) See Underwriting (Conflicts of Interest) for a description of underwriting compensation payable in connection with this offering.

The underwriters expect to deliver the shares of common stock on or about June 18, 2014.

Joint Book-Running Managers

Citigroup **Barclays**

BofA Merrill Lynch **BMO Capital Markets** **Goldman, Sachs & Co.**

Raymond James **RBC Capital Markets** **Wells Fargo Securities**

Co-Managers

Comerica Securities **Credit Suisse**

Mitsubishi UFJ Securities	**Morgan Stanley**
Scotiabank / Howard Weil	**Simmons & Company International**
Stephens Inc.	**Stifel**
UBS Investment Bank	**Wunderlich Securities**

The date of this prospectus is June 12, 2014.

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You should rely only on the information contained in this prospectus. Neither we, MRD Holdco LLC, nor the underwriters have authorized any person to provide you with any information or represent anything about us or this offering that is not contained in this prospectus. If given or made, any such other information or representation should not be relied upon as having been authorized by us. Neither we nor MRD Holdco LLC are making an offer in any jurisdiction where an offer or sale is not permitted. The information contained in this prospectus is current only as of its date.

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Commonly Used Defined Terms

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. Following the restructuring transactions described below, we will own the general partner of MEMP as well as 50% of MEMP s incentive distribution rights;

- MEMP GP refers to Memorial Production Partners GP LLC, the general partner of the Partnership, which we will own following completion of the restructuring transactions described below;

- MRD Holdco refers to MRD Holdco LLC, a holding company owned by the Funds that will own shares of our common stock following completion of the restructuring transactions described below and this offering, assuming that the underwriters do not exercise their option to purchase additional shares from MRD Holdco.

- MRD LLC refers to Memorial Resource Development LLC, which has historically owned our predecessor s business and will be merged into MRD Operating LLC, our subsidiary, after completion of the restructuring transactions described below;

- WildHorse Resources refers to WildHorse Resources, LLC, which owns our interest in the Terryville Complex and will be our 100% owned subsidiary following completion of the restructuring transactions described below;

- 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 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 own MRD Holdco;

- restructuring transactions means the transactions described beginning on page 13 that will take place in connection with and after the closing of this offering and pursuant to which we will acquire assets of MRD LLC (not including its interests in BlueStone, MRD Royalty, MRD Midstream, Golden Energy Partners LLC or Classic Pipeline) that comprise substantially all of the assets of MRD LLC;

- BlueStone refers to BlueStone Natural Resources Holdings, LLC, which 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, which owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana;

MRD Midstream refers to MRD Midstream LLC, which owns an indirect interest in certain immaterial midstream assets in North Louisiana; and

Classic Pipeline refers to Classic Pipeline & Gathering, LLC, which owns certain immaterial midstream assets in Texas.

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Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates. Although we believe these third-party sources are reliable and that the information is accurate and complete, neither we nor MRD Holdco have independently verified the information.

Equivalency

This prospectus presents certain production and reserves-related information on an equivalency basis. When we refer to oil and natural gas in equivalents, we are doing so to compare quantities of oil with quantities of natural gas. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil and/or NGLs is equivalent to six Mcf of natural gas. This calculation is based on an approximate energy equivalency and does not imply or reflect a value or price relationship.

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SUMMARY

This summary highlights information appearing elsewhere in this prospectus. You should read the entire prospectus carefully, including Risk Factors beginning on page 25 and the historical and pro forma financial statements and the related notes to those financial statements. Certain oil and gas industry terms, including the terms proved reserves, probable reserves and possible reserves, used in this prospectus are defined in the Glossary of Oil and Natural Gas Terms in Appendix A of this prospectus.

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. Except with respect to our consolidated and combined financial statements or as otherwise indicated, the description of our business, properties, strategies and other information in this summary does not include the business, properties or results of operations of BlueStone, MRD Royalty, MRD Midstream and Classic Pipeline (the assets of which are included in our predecessor but will not be conveyed to us in the restructuring transactions) or MEMP. Our proved reserves as of December 31, 2013 have been prepared by Netherland, Sewell & Associates, Inc., our independent reserve engineers (NSAI), and our probable and possible reserves as of December 31, 2013 have been prepared by our internal reserve engineers and audited by NSAI, all of which are reflected in our reserve reports (which we collectively refer to as our reserve report), summaries of which are included in Appendices B-1 and B-2 of this prospectus.

Information expressed on a pro forma basis in this summary gives effect to certain transactions as if they had occurred on March 31, 2014 for pro forma balance sheet purposes and on January 1, 2013 for pro forma statements of operations purposes. For a description of these transactions, please read Summary Historical Consolidated and Combined Pro Forma Financial Data and Our Structure and Restructuring Transactions.

Overview

We are an independent natural gas and oil company focused on the exploitation, development, and acquisition of natural gas, NGL 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. Our total leasehold position is 347,458 gross (205,818 net) acres, of which 60,041 gross (51,522 net) acres are in what we believe to be the core of the Terryville Complex. We are focused on creating shareholder value primarily through the development of our sizeable horizontal inventory. As of December 31, 2013, we had 1,582 gross (1,091 net) identified horizontal drilling locations, of which 1,431 gross (994 net) identified horizontal drilling locations are located in the Terryville Complex. These total net identified horizontal drilling locations represent an inventory of over 32 years based on our expected 2014 drilling program. We believe our inventory to be repeatable and capable of generating high returns based on the extensive production history in the area, the results of our horizontal wells drilled to date, and the consistent reservoir quality across multiple target formations.

As of December 31, 2013, we had estimated proved, probable and possible reserves of approximately 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe, respectively. As of such date, we operated 98% of our proved reserves, 71% of which were natural gas. For the three months ended March 31, 2014, 52% of our pro forma MRD Segment revenues were attributable to natural gas production, 24% to NGLs and 24% to oil. For the three months ended March 31, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $67 million and pro forma net income of $15.9 million, and made pro forma capital expenditures of $83 million. For the year ended December 31, 2013, we generated pro forma MRD Segment Adjusted EBITDA of $159 million and pro forma

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net income of $11.7 million, and made pro forma total capital expenditures of $203 million. Please see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA for an explanation of the basis for the pro forma presentation and our use of Adjusted EBITDA to measure the MRD Segment s profitability.

Our average net daily production for the three months ended March 31, 2014 was 168 MMcfe/d (approximately 70% natural gas, 21% NGLs and 9% oil) and our reserve life was 18 years. As of December 31, 2013, we produced from 95 horizontal wells and 800 vertical wells. The Terryville Complex represented 85% of our total net production for the three months ended March 31, 2014. Our estimated average net daily production for the period from April 1 through April 30, 2014 was 179 MMcfe/d, of which 73% was from natural gas. Our estimated average net daily production from our properties in the Terryville Complex for the same period was 141 MMcfe/d, or 79% of our total production. In the Terryville Complex, we have completed and brought online six additional horizontal wells since January 1, 2014, bringing our total number of producing horizontal wells to 27 in our primary formations. The 30 day production average rates of our four most recent wells averaged 25.1 MMcfe/d per well.

The following chart provides information regarding our production growth and the increasing proportion of our horizontal well production since the beginning of 2012.

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. To date, operators have drilled over 600 horizontal Cotton Valley wells. Some large, analogous redevelopment projects in the Cotton

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Valley include the Nan-Su-Gail Field in Freestone County, East Texas, where over 40 horizontal wells have been drilled by operators such as Devon Energy Corporation and Marathon Oil Corporation, and the Carthage Complex in Panola County, East Texas, where operators such as ExxonMobil Corporation, BP America, Memorial Production Partners LP and Anadarko Petroleum Corporation have drilled over 153 horizontal wells.

Cotton Valley Terryville Complex Horizontal Redevelopment

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 60,041 gross (51,522 net) acres as of December 31, 2013. The majority of our current and planned development is focused in and around what we believe to be the core of the Terryville Complex.

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 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. We intend to dedicate approximately $264 million of our $312 million drilling and completion budget in 2014 to develop multiple zones within the Terryville Complex, where we expect to drill and complete 35 gross (30 net) wells. Our horizontal redevelopment program in the Terryville Complex will be focused on increasing our well performance and recoveries.

Within the Terryville Complex, as of December 31, 2013, we had 945 Bcfe, 688 Bcfe and 1,643 Bcfe of estimated proved, probable and possible reserves, respectively, and a drilling inventory consisting of 1,431 gross (994 net) identified horizontal drilling locations, including 91 gross (72 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. Since initiating our horizontal drilling program in 2011, we have drilled 27 gross (22.0 net) horizontal wells, growing our gross daily production in the Terryville Complex by 304% from 53.0 MMcfe/d for the three months ended March 31, 2010 to 214.0 MMcfe/d for the month ended April 30, 2014. For the three months ended March 31, 2014, 51% of our revenues from the Terryville Complex were attributable to natural gas, 25% to NGLs and 24% to oil. Within the Terryville Complex, on a proved reserves basis, we operate approximately 99% of our existing acreage and hold an average working interest of approximately 74% across our acreage. Our high operating control allows us to more efficiently and economically manage the redevelopment of this extensive resource.

We believe seismic data, as well as information gathered from the results of our existing 275 vertical and 27 horizontal wells throughout the field, support the existence of at least ten stacked pay zones across the Terryville Complex. Our redevelopment program currently targets four of the stacked 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 400 to 890 feet across our acreage position. We believe the overpressured nature of this section of the Cotton Valley formation is highly productive when accessed through horizontal drilling and fracture

stimulation technologies. These qualities, when combined with the liquids-rich nature of the natural gas, high initial rates of production and competitive well costs, produce what we believe to be amongst the highest rate of return wells in the nation. Further, there are additional opportunities for redevelopment in the zones above the four main zones. NSAI has allocated over $1 billion PV-10 and 677 Bcfe to our possible reserve category for the redevelopment of these additional zones. Please see Reserves.

The table below details certain information on estimated ultimate recoveries and production for the 27 horizontal wells currently producing in the Terryville Complex. Our well results have shown consistency in initial production, decline rates and estimated ultimate recovery. The consistency of these results gives us confidence that the full-scale redevelopment of the Terryville Complex we began in 2013 will be successful as we move from four to five rigs in 2014. Please see Business Our Properties Cotton Valley Terryville Complex Horizontal Redevelopment for more detail on our properties in the Terryville Complex and the table on page 98 for more detail on the average EUR and cumulative production of our properties in the Terryville Complex.

	Producing Wells						Gross Wellhead Flow Rates After Processing (MMcfe/d)(3)(4)				
Well Name (1)	Lateral Length (Feet)	EUR (Bcfe)(2)	EUR BCFe/ 1,000	First Production	Days Producing	Cumulative Production (Bcfe)	0-30	0-90	91-180	181-360	D&C ($MM)
Upper Red Zone											
LD Barnett 23H-2	4,015	13.6	3.4	1/30/2012	842	4.6	14.5	12.0	7.7	5.6	6.7
Colquitt 20 17H-1	4,357	11.2	2.6	7/30/2012	660	3.9	17.5	12.6	7.2	5.1	7.7
Dowling 22 15H-1	5,376	16.8	3.1	9/22/2012	606	5.2	16.3	15.6	11.1	8.2	8.8
Nobles 13H-1	4,216	11.6	2.8	11/17/2012	550	4.3	21.5	16.7	9.9	6.5	7.8
Sidney McCullin 16 21H-1	4,604	16.9	3.7	1/19/2013	487	4.5	17.4	14.2	10.8	8.4	8.1
Wright 14 11 HC-1	5,250	18.0	3.4	5/27/2013	359	4.6	19.6	18.1	16.1	8.5	8.8
BF Fallin 22 15H-1	5,122	15.6	3.0	6/17/2013	338	3.2	14.8	13.7	11.8		7.5
Dowling 20 17H-1	4,327	8.9	2.1	7/22/2013	303	2.1	15.2	11.0	5.7		10.7
Gleason 31H-1	3,692	2.5	0.7	8/12/2013	282	0.5	3.5	2.7	1.8		9.4
Burnett 26H-1	2,405	4.2	1.7	9/22/2013	241	0.9	6.9	5.5	3.3		6.6
Drewett 17 8H-1	4,010	14.0	3.5	11/13/2013	189	2.9	22.1	18.7	12.3		7.7
Wright 13 12 HC-2	6,009	18.1	3.0	12/21/2013	151	2.7	22.7	19.5			8.0
LA Minerals 15 22H-2	5,814	N/A	N/A	1/21/2014	120	1.9	18.1	16.7			9.3
TL McCrary 14 11 HC-5	5,875	N/A	N/A	4/14/2014	37	0.9	25.3				7.8
Wright 13 24 HC-1	6,678	N/A	N/A	4/14/2014	37	0.8	23.2				8.9
Wright 13 24 HC-3	6,606	N/A	N/A	4/14/2014	37	1.0	28.1				7.6
Lower Red Zone											
TL McCrary 14H-1	4,544	12.8	2.8	5/1/2012	750	4.0	14.4	11.7	8.3	5.4	7.7
Nobles 13H-2	4,060	9.2	2.3	11/17/2012	550	3.1	16.0	11.9	8.4	5.2	7.8
LA Methodist Orphanage 14H-1	3,637	12.1	3.3	2/15/2013	460	3.6	13.9	13.0	9.7	6.3	9.1
Dowling 21 16H-1	4,590	9.4	2.0	3/18/2013	429	2.6	13.0	10.1	6.5	4.5	6.6
Drewett 17 8H-2	3,700	3.7	1.0	11/13/2013	189	0.9	8.7	6.2	3.2		6.8
Wright 13 12 HC-1	5,409	8.2	1.5	12/21/2013	151	1.5	14.7	11.3			9.1
LA Minerals 15 22H-1	5,926	N/A	N/A	1/21/2014	120	1.2	13.8	11.1			8.0
Wright 13 24 HC-4	6,518	N/A	N/A	4/14/2014	37	0.8	23.8				10.3
Lower Deep Pink Zone											
LA Methodist Orphanage 14H-2	3,550	12.2	3.4	2/15/2013	460	3.2	14.2	11.6	7.6	5.6	6.1
Wright 13 12 HC-3	5,706	6.3	1.1	12/21/2013	151	1.2	12.5	9.3			7.1
Wright 13 12 HC-4	5,010	5.0	1.0	12/21/2013	151	1.1	11.8	8.8			6.1
Averages											
All Wells	**4,852**	**11.0**	**2.5**		**322**	**2.5**	**16.4**	**12.3**	**8.3**	**6.3**	**8.0**
Upper Red	**4,897**	**12.6**	**2.7**		**327**	**2.8**	**17.9**	**13.6**	**8.9**	**7.0**	**8.2**
Lower Red	**4,798**	**9.2**	**2.2**		**336**	**2.2**	**14.8**	**10.8**	**7.2**	**5.4**	**8.2**
Lower Deep Pink	**4,755**	**7.8**	**1.8**		**254**	**1.8**	**12.8**	**9.9**	**7.6**	**5.6**	**6.4**

(1) The majority of the wells in this table are included within our proved developed producing reserve category in our reserve report as of December 31, 2013. LA Minerals 15 22H-1, LA Minerals 15 22H-2, TL McCrary 14 II HC-5, Wright 13 24 HC-1, Wright 13 24 HC-3 and Wright 13 24 HC-4 each started producing in 2014 so they have not been included in the year-end reserve report as proved developed producing.

(2) EUR represents the Estimated Ultimate Recovery or sum of total gross remaining proved reserves attributable to each location in our reserve report and cumulative sales from such location. EUR is shown on a combined basis for oil/condensates, gas and NGLs after the effects of processing.

(3) Production data is as of May 21, 2014 and shown gross on a combined basis after the effects of processing.

(4) Periodic flow rates start on day 4, with days 1 through 3 used to allow clean up associated with well completion. The 30-day flow rates therefore start on day 4 and continue 30 days to day 33 and the 90-day flow rates go from day 4 to day 93.

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Recent Drilling Updates

During the week of April 14, 2014, we completed four new wells in the Terryville Complex. The combined 30 day production average for the four wells was 100.4 MMcfe per day. Three of the wells were drilled on one pad in the eastern edge of our property, the farthest step out from our core position to date, and produced a combined 30 day production average of 75.1 MMcfe per day.

East Texas

We own and operate approximately 54,337 gross (42,894 net) acres as of December 31, 2013 in Texas, where we are currently producing primarily from the Cotton Valley, Travis Peak and Bossier formations and targeting the Cotton Valley formation for future development. From January 1, 2011 through December 31, 2013, we have drilled and completed 28 gross (10.3 net) wells and are operating one rig in East Texas as of December 31, 2013. In 2014, we plan to invest $36 million to drill and complete 8 gross (6 net) wells in East Texas in the Joaquin Field of Panola and Shelby Counties. As of December 31, 2013, we had approximately 108 gross identified horizontal drilling locations in East Texas, including 54 gross (43 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. For the three months ended March 31, 2014, our average net daily production from our East Texas properties was 21 MMcfe/d, of which 74% was natural gas. Within our East Texas properties, on a proved reserves basis, we operate approximately 94% of our existing properties.

Rockies

We own approximately 162,375 gross (66,191 net) acres as of December 31, 2013 in our Rockies region and for the three months ended March 31, 2014 our average net daily production from this region was 4 MMcfe/d. In 2014, we plan to operate one rig and invest $12 million to drill 3 gross (3 net) vertical wells in the Tepee Field of the Piceance Basin targeting the Mancos and Williams Fork formations. As of December 31, 2013, we had approximately 174 gross identified vertical drilling locations in the Tepee Field in our Rockies properties.

Reserves

Our estimates of proved reserves are prepared by NSAI, and our estimates of probable and possible reserves are prepared by our management and audited by NSAI. As of December 31, 2013, we had 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe of estimated proved, probable and possible reserves, respectively. As of this date, our proved reserves were 71% gas and 29% NGLs and oil. Additionally, the PV-10 of our proved reserves was $1,469 million, the PV-10 for our probable reserves was $1,052 million and the PV-10 for our possible reserves was $2,386 million. The following table provides summary information regarding our estimated proved, probable and possible reserves data by area based on our reserve report as of December 31, 2013 and our average net daily production by area for the three months ended March 31, 2014:

	Proved Total (Bcfe)	% Gas	% Developed	Proved PV-10 (in millions)(1)	Probable Total (Bcfe)(2)	Probable PV-10 (in millions)(1)	Possible Total (Bcfe)(2)	Possible PV-10 (in millions)(1)	Average Net Daily Production (MMcfe/d)
Terryville Complex	945	71%	33%	$ 1,341	688	$ 1,032	1,643	$ 2,383	143
East Texas	175	75%	29%	110	109	18	66	3	21
Rockies	6	49%	100%	18	2	2	2	1	4
Total	1,126	71%	33%	$ 1,469	800	$ 1,052	1,711	$ 2,386	168

(1) In this prospectus, we have disclosed our PV-10 based on our reserve report. PV-10 is a non-GAAP financial measure and represents the period-end present value of estimated future cash inflows from our natural gas and crude oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using SEC pricing assumptions in effect at the end of the period. SEC pricing for natural gas and oil of $3.67 per Mcf and $93.42 per Bbl was based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding December 2013. PV-10 differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized estimates of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. In addition, investors should be cautioned that estimates of PV-10 for probable and possible reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Our PV-10 estimates of proved reserves and our standardized measure are equivalent because, prior to the completion of this offering, we were not subject to entity level taxation. Accordingly, no provision for federal income taxes has been provided because taxable income has been passed through to our equity holders. However, had we not been a tax exempt entity as of December 31, 2013, our estimated discounted future income tax in respect of our proved, probable and possible reserves would have been approximately $401 million, $368 million and $835 million, respectively. After this offering, we will be treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor standardized measure represents an estimate of fair market value of our natural gas and oil properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities.

(2) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

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Drilling Inventory and Capital Budget

We intend to develop our multi-year drilling inventory by utilizing our significant expertise in horizontal drilling and fracture stimulation to grow our production, reserves and cash flow. For 2014, we have budgeted a total of $312 million to drill and complete 46 gross (39 net) operated wells. We expect to fund our 2014 development primarily from cash flows from operations. The majority of our drilling locations and our 2014 development program are focused on the Terryville Complex, where we plan to invest $264 million on drilling and completing 33 gross (28 net) horizontal wells and 2 gross (2 net) vertical wells. Approximately $5.0 million of our Terryville Complex budget is allocated towards the drilling of vertical wells and routine facilities maintenance. In East Texas, we plan to invest $36 million on drilling and completing 8 gross (6 net) horizontal wells. In the Rockies, we plan to invest $12 million on drilling and completing 3 gross (3 net) vertical wells in the Tepee Field.

The following table provides information regarding our acreage and drilling locations by area as of December 31, 2013, except for projected 2014 information:

			Gross Horizontal Drilling Locations(1)(2)								
							Total			2014	
	Net Acreage	WI%	Proved	Probable	Possible	Management	Gross	Net	Net Horizontal Drilling Inventory (years)	Projected Operated Net Wells to be Drilled	2014 Projected Capital Budget ($MM)
Terryville Complex	96,733	74%	91	147	450	743	1,431	994	36	30	$ 264
East Texas	42,894	79%	54	39	15		108	92	15	6	36
Rockies	66,191	41%		23	20		43	4		3	12
Total	205,818	59%	145	209	485	743	1,582	1,091	32	39	$ 312

(1) The above table excludes 192 proved vertical drilling locations in our reserve report in the Terryville Complex and 174 identified vertical locations based on management estimates in the Rockies.

(2) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business 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. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.

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Our extensive inventory and horizontal drilling program in the Terryville Complex is currently focused on four zones within the Cotton Valley formation the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. The table below sets forth our drilling locations by zone as of December 31, 2013 along with the average results for the wells we have drilled within each zone. Please see Business Our Properties Cotton Valley Terryville Complex Horizontal Redevelopment for more detail on our properties in the Terryville Complex and the table on page 98 for the 30 day initial production rate and EUR condensate volumes.

Lower Cotton	Gross Horizontal Drilling Locations(1)					Average Historical Results(2)		
Valley Zone	Proved	Probable	Possible	Management	Total	Producing Wells Drilled(1)	EUR (Bcfe)(3)	Drilling and Completion Costs ($MM)
Upper Red	47	42	40	313	442	16	12.6	$ 8.2
Lower Red	40	40	36	276	392	8	9.2	$ 8.2
Lower Deep Pink	4	28	47	79	158	3	7.8	$ 6.4
Upper Deep Pink		37	42	75	154			
Other Zones			285		285			
Total Terryville Complex	91	147	450	743	1,431	27	11.0	$ 8.0

(1) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business 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. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.

(2) Relates to the 21 horizontal wells in the Terryville Complex included in our reserve report as proved developed reserves as of December 31, 2013. Drilling and completion costs and producing wells drilled include six additional wells that have come online since year-end.

(3) EUR represents the Estimated Ultimate Recovery or the sum of total gross remaining proved reserves attributable to each location in our reserve report and cumulative sales from such location. EUR is shown at the wellhead on a combined basis for oil/condensates and wet gas.

Our Terryville horizontal development program in 2014 has an average working interest of 87% and our total horizontal development inventory has an average working interest of 69%.

For the Terryville Complex, our 2014 budget assumes an average cost of $8.6 million for gross horizontal wells ($7.5 million per net well) and is based on an average lateral length of 6,270 feet. As part of our long-term development plan, the lateral length of our planned wells is expected to increase and we expect wells within the Terryville Complex to cost on average $9.3 million for gross wells ($8.1 million per net well) drilled with a 7,500 foot lateral length.

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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. As of December 31, 2013, we had assembled an aggregate drilling inventory of 1,582 gross identified horizontal drilling locations, 90% of which are in the Terryville Complex, representing a drilling inventory of over 36 years based on our expected 2014 drilling program. We believe that the risk and uncertainty associated with our core acreage positions in the Terryville Complex has been largely reduced through our development activity, and because those positions are in areas with extensive drilling and production history. Since initiating our horizontal drilling program with one rig in 2011, we have invested over $349 million in the Terryville Complex through March 31, 2014. With four rigs running in the Terryville Complex as of December 31, 2013, we are one of the most active drillers in the Cotton Valley formation. We intend to dedicate approximately $264 million of our $312 million drilling and completion budget in 2014 to develop the overpressured liquids-rich Terryville Complex through multi-well pad drilling. 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. We also believe our East Texas region has a significant inventory of low-risk, liquids-rich horizontal drilling locations. Finally, we continue to evaluate our leasehold positions in the Rockies and have preliminarily identified over 170 potential vertical locations.

Maintain a disciplined, growth oriented financial strategy. We intend to fund our growth primarily with internally generated cash flows 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 liquidity to fund our drilling program. Since approximately 76% of our acreage in the Terryville Complex was held by production as of December 31, 2013 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

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addition to our focus on the Terryville Complex, we are pursuing 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, amassing a land position of 96,733 net acres, 51,522 net acres of which we believe to be in the core of the play. 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. We own approximately 60,041 gross (51,522 net) acres in what we believe to be the core of 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. Through December 31, 2013, our drilling program in the Terryville Complex has produced some of the top performing gas wells in the United States in the previous two years, with single horizontal well results having achieved EURs averaging 11.0 Bcfe per well. Through May 21, 2014, we have brought 27 wells on online with average 30-day initial production rates of 16.4 MMcfe/d and average drilling and completion costs of $8.0 million per well. Approximately 76% of our acreage in the Terryville Complex was held by production at December 31, 2013 and there are no significant lease expirations until 2017. Additionally, all of our acreage in this play can be held by running a one rig program over the next 18 months.

De-risked acreage position with multi-year inventory of liquids-rich drilling opportunities. As of December 31, 2013, we had a drilling inventory consisting of 1,582 gross identified horizontal drilling locations, of which approximately 145 are gross proved undeveloped locations. Based on our expected 2014 drilling program and net identified drilling locations, we have over 32 years of liquids-rich drilling inventory. 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 three months ended March 31, 2014, 52% of our pro forma MRD Segment revenues were attributable to natural gas, 24% to NGLs and 24% to oil.

Significant operational control with low cost operations. On a proved reserves basis, we operate 99% 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 and its geologic continuity, we are able to drill consistently long laterals, averaging over 4,800 lateral feet, which helps us to reduce costs on a per-lateral foot basis and increase our returns. We expect the average lateral length of the 35 gross wells that we expect to drill in the Terryville Complex in 2014 to be 6,400 feet per well. Operating in mature basins in North Louisiana and East Texas 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 MRD Segment lease operating costs declining 20% from $0.47 per Mcfe for the three months ended March 31, 2013 to $0.38 per Mcfe for the three months ended March 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 22 years of experience in the oil and natural gas industry. John A. Weinzierl, our Chief Executive Officer, has 24 years of oil and natural gas industry experience as a petroleum engineer, a strong commercial and technical 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 as well as 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 drop-down transactions with MEMP totaling approximately $376 million. 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. During 2013, we generated $159 million of pro forma MRD Segment Adjusted EBITDA and made pro forma total capital expenditures of $203 million. During the three months ended March 31, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $67 million and made pro forma capital expenditures of $83 million. We intend to continue to fund our organic growth predominantly with internally generated cash flows while maintaining ample liquidity for opportunistic acquisitions. We will continue to maintain a disciplined approach 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 three-to-five year rolling hedge program. Pro forma as of March 31, 2014 for this offering and the restructuring transactions (including the redemption of the PIK notes for approximately $360 million 30 days after the closing of this offering), we expect our total liquidity, consisting of cash on hand and available borrowing capacity under our new revolving credit facility, to be in excess of $140 million.

Recent Developments

In December 2013, MRD LLC issued $350,000,000 of its 10.00%/10.75% Senior PIK toggle notes due 2018, which we refer to as the PIK notes. MRD LLC used the net proceeds from that issuance to repay outstanding indebtedness, to fund a debt service reserve account for the payment of interest on the PIK notes, to pay a distribution to the Funds, and for general company purposes. In connection with the closing of this offering, we will assume the PIK notes and use a portion of the proceeds of this offering to redeem the PIK notes in their entirety, to pay any applicable premium in connection with such redemption and to pay accrued and unpaid interest, if any, to the date of redemption. MRD Holdco will receive the cash released upon the termination of the debt service reserve account in connection with the redemption of the PIK notes. See Restructuring Transactions.

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In April 2014, we sold approximately 15 Bcfe of proved reserves located in East Texas to MEMP for cash consideration of approximately $34.0 million, subject to customary post-closing adjustments.

In May 2014, we sold certain producing and non-producing properties (consisting of 43 gross (4 net) wells) in the Mississippian oil play of Northern Oklahoma to a third party for cash consideration of approximately $6.7 million, subject to customary post-closing adjustments.

In connection with the closing of this offering, we intend to enter into a new $2.0 billion revolving credit facility. Immediately prior to the closing of this offering, we will borrow approximately $616.7 million from our new revolving credit facility primarily to pay off and terminate in their entirety WildHorse Resources revolving credit facility and second lien term loan, which we refer to collectively as WildHorse Resources credit agreements. See Restructuring Transactions.

Acquisition History

We built out our leasehold positions in North Louisiana, East Texas and the Rocky Mountains primarily through the following acquisition activities:

- In November 2007, we acquired interests in the Joaquin Field, which is the core of our East Texas acreage;
- In December 2007, we acquired interests in the Tepee Field in the Piceance Basin in Colorado;
- In April and May 2010, we acquired interests in the Terryville Complex and other North Louisiana fields, which are the core of our North Louisiana acreage;
- In November 2010, we acquired interests in the Spider and E. Logansport Fields in North Louisiana;
- In May 2012, we acquired interests in the Terryville Complex and Double A Field in North Louisiana and East Texas;
- In April 2013, we acquired interests in the West Simsboro and Simsboro Fields of the Terryville Complex in North Louisiana;
- In November 2013, we acquired the remaining equity interests in Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C. and Black Diamond Minerals, LLC, which hold oil and natural gas properties in East Texas, North Louisiana and the Rocky Mountains; and
- In February 2014, we repurchased net profits interests in the Terryville Complex 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.

Our Principal Stockholder

Our principal stockholder is MRD Holdco, which is controlled by the Funds, which are three of the private equity funds managed by NGP. Upon completion of this initial public offering, MRD Holdco, the selling stockholder in this offering, will own approximately 55.8% of our common stock (or approximately 52.4% if the underwriters option to purchase additional shares from MRD Holdco is exercised in full). Pursuant to a voting agreement, MRD Holdco will also have the right to direct the vote of an additional approximately 22.0% of our common stock. The Funds also collectively indirectly own 50% of MEMP s incentive distribution rights, and at the completion of this offering MRD Holdco will own 5,360,912 subordinated units of MEMP, representing an 8.7% limited partner interest in MEMP. We are also a party to certain other agreements with MRD Holdco, the Funds and certain of their affiliates. For a description of the voting agreement and these other agreements, please read Certain Relationships and Related Party Transactions.

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Founded in 1988, NGP is a family of private equity investment funds, with cumulative committed capital of approximately $10.5 billion since inception, organized to make investments in the natural resources sector. NGP is part of the investment platform of NGP Energy Capital Management, a premier investment franchise in the natural resources industry, which together with its affiliates has managed approximately $13 billion in cumulative committed capital since inception.

Our Interest in Memorial Production Partners LP

Through our ownership of its general partner, we control MEMP. We also own 50% of its incentive distribution rights. MEMP is a publicly traded limited partnership 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. 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. Because we control MEMP, we are required to consolidate MEMP for accounting and financial reporting purposes, even though we and MEMP have independent capital structures.

During each of the year ended December 31, 2013 and three months ended March 31, 2014, less than $0.1 million of distributions were made in respect of the MEMP incentive distribution rights. Please see Business Relationship with Memorial Production Partners LP for further information on our interest in MEMP.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile commodity prices and other material factors. For a discussion of these risks and other considerations that could negatively affect us, including risks related to this offering and our common stock, please read Risk Factors beginning on page 25 of this prospectus and Cautionary Note Regarding Forward-Looking Statements.

Our Structure and Restructuring Transactions

We are a Delaware corporation formed by MRD LLC to own and acquire oil and natural gas properties. In connection with the closing of this offering, the following transactions, which we refer to as the restructuring transactions, will occur:

- The Funds will contribute all of their interests in MRD LLC to MRD Holdco;
- WildHorse Resources will sell its subsidiary, WildHorse Resources Management Company, LLC (which holds certain immaterial assets related to our WildHorse Resources operations) to an affiliate of the Funds for approximately $0.2 million in cash, and that subsidiary will enter into a services agreement with WildHorse Resources pursuant to which that subsidiary will provide transition services to WildHorse Resources;

Classic Hydrocarbons Holdings, L.P. and Classic Hydrocarbons GP Co., L.L.C. will distribute to MRD LLC the ownership interests in Classic Pipeline, which owns certain immaterial midstream assets in Texas, and Black Diamond Minerals, LLC will distribute to MRD LLC its ownership interests in Golden Energy Partners LLC, which sold all of its assets in May 2014;

MRD LLC will contribute to us substantially all of its assets, comprised of:

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;

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99.9% of the membership interests in WildHorse Resources, the owner of our properties in the Terryville Complex; and

MEMP GP (including MEMP GP s ownership of 50% of MEMP s incentive distribution rights);

We will issue 128,665,677 shares of our common stock to MRD LLC, which MRD LLC will immediately distribute to MRD Holdco;

We will assume the obligations of MRD LLC under the PIK notes, including the obligation to reimburse MRD LLC for the June 15, 2014 interest payment made on the PIK notes;

Certain former management members of WildHorse Resources will contribute 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 will issue 42,334,323 shares of our common stock and pay cash consideration of $30.0 million to such former management members of WildHorse Resources;

We will enter into a registration rights agreement and a voting agreement with MRD Holdco and certain former management members of WildHorse Resources;

We will enter into our new $2.0 billion revolving credit facility and will use approximately $616.7 million in borrowings under that facility to repay all amounts outstanding under WildHorse Resources credit agreements, to pay 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;

Our subsidiary MRD Operating LLC will enter into a merger agreement with MRD LLC pursuant to which (i) after the redemption of the PIK notes as described below, MRD LLC will merge into MRD Operating LLC, (ii) until the date of such merger, MRD LLC will perform under certain ancillary commercial contracts to which it is a party in support of its current operations for our benefit (such as office leases and drilling contracts), (iii) all amounts received under such contracts will be for our benefit and (iv) we will be responsible for all amounts owing under such contracts; and

We will give notice of redemption to the holders of the PIK notes, which will specify a redemption date of 30 days after the closing of this offering, and we will use a portion of the net proceeds from this offering to redeem all outstanding PIK notes, including paying any applicable premium and accrued and unpaid interest, if any, to the date of redemption. Until the redemption date, or any earlier discharge date as noted below, of the PIK notes, we will use the amount to be paid to the holders of these notes to temporarily reduce amounts outstanding under our new revolving credit facility.

From the closing date of this offering until the date upon which the PIK notes are redeemed and the PIK notes indenture is terminated, MRD LLC will remain a subsidiary of MRD Holdco. During that time, MRD LLC will distribute to MRD Holdco:

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 immaterial midstream assets in North Louisiana, Golden Energy Partners LLC and Classic Pipeline;

5,360,912 subordinated units of MEMP representing an approximate 8.7% limited partner interest in MEMP;

The right to the remaining cash to be released from the debt service reserve account in connection with the redemption 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

Approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy Partners LLC s assets in May 2014.

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The redemption date of the PIK notes will be approximately 30 days after the closing of this offering. We will have the option to pay the full redemption amount (including any applicable premium and accrued and unpaid interest to the redemption date) to the PIK notes trustee at any time before the redemption date. If we deposit that amount with the PIK notes trustee in advance of the redemption date together with irrevocable instructions to use such amount for the redemption on the redemption date, then our obligations under the PIK notes indenture will be discharged on the date of such deposit. We may choose to so deposit that amount with the PIK notes trustee in advance of the redemption date. After the PIK notes indenture is terminated or discharged, as the case may be, MRD LLC will merge into MRD Operating LLC. At that time, MRD LLC s sole assets will be the commercial contracts noted above, which relate to the businesses owned by us.

Please read Use of Proceeds and Restructuring Transactions for more information about the application of the net proceeds from this offering and the restructuring transactions. For more information regarding BlueStone, see Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations MRD Segment. For more information about the services agreement with WildHorse Resources, see Certain Relationships and Related Party Transactions Services Agreement.

The following diagram shows our ownership structure after giving effect to the restructuring transactions and this offering, assuming no exercise of the underwriters option to purchase additional shares from MRD Holdco and does not give effect to 19,250,000 shares of common stock reserved for future issuance under the Memorial Resource Development Corp. 2014 Long Term Incentive Plan (described in Management 2014 Long Term Incentive Plan) or our intended grant of 1,068,421 restricted shares of common stock to our independent directors and certain of our employees under such plan in connection with a successful completion of this offering. See Management Executive Compensation Compensation Following This Offering IPO Bonuses. For information regarding our ownership structure before giving effect to the restructuring transactions and this offering, see the diagram on page 154 in Restructuring Transactions.

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(1) If the underwriters exercise in full their option to purchase additional shares of common stock from MRD Holdco, the ownership interest of the public stockholders will increase to 49,220,000 shares of common stock, representing an aggregate 25.6% ownership interest in us, and MRD Holdco will own 100,945,677 shares of common stock, representing an aggregate 52.4% ownership interest in us.

(2) As of March 31, 2014.

(3) 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 own all of the membership interests in MRD Holdco. Please read Principal and Selling Stockholders for information regarding beneficial ownership. The Funds collectively indirectly own 50% of the Partnership s incentive distribution rights.

(4) Subsidiaries of MRD Holdco following the restructuring transactions will include 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). Also, please see the Principal and Selling Stockholders table on page 145 for the beneficial ownership of our shares by our executive officers and directors.

(5) Includes Classic Hydrocarbons Holdings, L.P. (Classic), Classic Hydrocarbons GP Co., L.L.C. (Classic GP), Black Diamond Minerals, LLC (Black Diamond), and Beta Operating Company, LLC (Beta Operating).

(6) Does not include restricted common stock to be issued to our independent directors and certain of our employees in connection with the completion of this offering.

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Corporate Information

Our principal executive offices are located at 1301 McKinney St., Suite 2100, Houston, Texas 77010, and our phone number is (713) 588-8300. Our website address is www.memorialrd.com. We expect to make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, which we refer to as 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.

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, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- provide certain disclosure regarding executive compensation required of larger public companies or hold shareholder advisory votes on executive compensation required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act); or
- obtain shareholder approval of any golden parachute payments not previously approved.

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

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

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

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, or the Securities Act, for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

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The Offering

Common stock offered by us	21,500,000 shares.
Common stock offered by MRD Holdco	21,300,000 shares (or 27,720,000 shares, if the underwriters exercise in full their option to purchase additional shares).
Common stock to be outstanding immediately after the offering(1)	192,500,000 shares.
Option to purchase additional shares	MRD Holdco has granted the underwriters a 30-day option to purchase up to an aggregate of 6,420,000 additional shares of our common stock held by MRD Holdco to cover over-allotments.
Common stock voting rights	Each share of our common stock will entitle its holder to one vote.
Use of proceeds	We intend to use the estimated net proceeds of approximately $382.1 million from this offering, after deducting underwriting discounts and commissions and fees and expenses associated with this offering and the restructuring transactions, to redeem the PIK notes in their entirety and to pay any applicable premium in connection with such redemption and accrued and unpaid interest, if any, to the date of redemption (which we expect will be 30 days after the closing of this offering); together with borrowings of approximately $616.7 million under our new revolving credit facility, 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; to repay borrowings outstanding under WildHorse Resources credit agreements; to reimburse MRD LLC for interest paid on the PIK notes; and to pay costs associated with our new revolving credit facility. Until the redemption date or any earlier discharge date of the PIK notes, we will use the amount to be paid to the holders of those notes to temporarily reduce amounts outstanding under our new revolving credit facility. See Use of Proceeds.
	We will not receive any of the proceeds from the sale of shares of our common stock by MRD Holdco, including pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock. MRD Holdco is deemed under federal securities laws to be an underwriter with respect to the common stock it may sell in connection with this offering.
Dividend policy	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 of directors (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. See Dividend Policy.

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Directed Share Program	The underwriters have reserved for sale at the initial public offering price up to 2% of the common stock being offered by this prospectus for sale to our employees, executive officers and directors who have expressed an interest in purchasing common stock in the offering. We do not know if these persons will choose to purchase all or any portion of these reserved shares, but any purchases they do make will reduce the number of shares available to the general public. Please read Underwriting (Conflicts of Interest) beginning on page 166.
Risk factors	You should carefully read and consider the information set forth under Risk Factors beginning on page 25 of this prospectus and all other information set forth in this prospectus before deciding to invest in our common stock.
Conflicts of Interest	An affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated will be a lender under the Company s new revolving credit facility and will receive more than 5% of the net proceeds of this offering in connection with the temporary repayment of amounts under such credit facility. See Use of Proceeds. Accordingly, this offering will be made in compliance with the applicable provisions of Rule 5121 of the Financial Industry Regulatory Authority, Inc. This rule requires that a qualified independent underwriter meeting certain standards participate in the preparation of the registration statement and prospectus and exercise the usual standards of due diligence with respect thereto. Simmons & Company International has agreed to act as a qualified independent underwriter within the meaning of Rule 5121 in connection with this offering. See Underwriting (Conflicts of Interest).
Listing and trading symbol	We have been approved to list our common stock on the NASDAQ Global Market (NASDAQ) under the trading symbol MRD.

(1) Does not include restricted shares of our common stock to be issued to our independent directors and certain of our employees in connection with the successful completion of this offering pursuant to our Plan (as defined herein). See Management Executive Compensation Compensation Following This Offering IPO Bonuses.

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Summary Historical Consolidated and Combined Pro Forma Financial Data

MRD LLC and its consolidated subsidiaries, our accounting predecessor, controls MEMP through its ownership of MEMP GP, the general partner of MEMP. Because MRD LLC controls MEMP through its ownership of the general partner, MRD LLC is required to consolidate MEMP for accounting and financial reporting purposes even though MRD LLC owns a minority of its partner interests and MRD LLC and MEMP have independent capital structures. MRD LLC receives cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP. In connection with the closing of this offering, MRD LLC will contribute substantially all of its existing assets to us in exchange for shares of our common stock. Through our ownership of MEMP GP, we will continue to control MEMP and therefore will continue to consolidate the results of MEMP into our consolidated financial statements in future periods.

Our predecessor has two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

MRD reflects all of MRD LLC s consolidating subsidiaries except for MEMP and its subsidiaries.

MEMP reflects the consolidated and combined operations of MEMP and its subsidiaries.

We will continue to have two reportable segments following the completion of this offering. For more information regarding reportable business segments, please see the predecessor s audited historical financial statements and related notes and our predecessor s unaudited historical interim financial statements included elsewhere in this prospectus.

The following tables include the summary historical financial data of our predecessor, as well as the MRD Segment as of and for the periods indicated. The summary historical financial data of our predecessor as of and for the years ended December 31, 2013 and 2012 were derived from the audited historical financial statements of our predecessor included elsewhere in this prospectus. The summary historical financial data of our predecessor as of March 31, 2014 and for the three months ended March 31, 2014 and 2013 were derived from the unaudited interim financial statements of our predecessor included elsewhere in this prospectus. The summary historical financial data of the MRD Segment as of and for the years ended December 31, 2013 and 2012 were derived from certain financial information used in the preparation of our predecessor s audited financial statements. The summary historical financial data for the MRD Segment as of March 31, 2014 and for the three months ended March 31, 2014 and 2013 were derived from certain financial information used in the preparation of our predecessor s unaudited interim financial statements.

The summary unaudited pro forma data as of and for the three months ended March 31, 2014 and for the year ended December 31, 2013 has been prepared to give pro forma effect to: (i) the exclusion of both BlueStone and Classic Pipeline, the MEMP subordinated units and the debt service reserve account associated with the PIK notes, which are not being conveyed to us in connection with this offering, as well as our reimbursement for the June 15, 2014 interest payment on the PIK notes, (ii) the offering of our shares of common stock contemplated hereby and the use of the net proceeds therefrom as described in Use of Proceeds, (iii) incremental federal income tax expense, and (iv) the restructuring transactions.

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We derived the data in the following tables from, and the following tables should be read together with and is qualified in its entirety by reference to, our predecessor s historical financial statements and our pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read Restructuring Transactions, Use of Proceeds, Management s Discussion and Analysis of Financial Condition and Results of Operations, and our pro forma and historical consolidated financial statements, all included elsewhere in this prospectus. Among other things, those historical consolidated and combined financial statements and pro forma financial statements include more detailed information regarding the basis of presentation for the following data.

	MRD LLC (Predecessor)				Memorial Resource Development Corp. Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31,	Three Months Ended March 31,
	2013	2012	2014	2013	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 571,948	$ 393,631	$ 189,917	$ 121,626	$ 553,800	$ 189,359
Other revenues	3,075	3,237	911	555	2,268	812
Total revenues	575,023	396,868	190,828	122,181	556,068	190,171
Costs and expenses:						
Lease operating	113,640	103,754	33,682	26,364	111,988	34,092
Pipeline operating	1,835	2,114	489	470	1,835	489
Exploration	2,356	9,800	146	856	2,356	146
Production and ad valorem taxes	27,146	23,624	8,584	7,286	26,269	8,558
Depreciation, depletion and amortization	184,717	138,672	57,679	43,206	174,198	57,369
Impairment of proved oil and gas properties	6,600	28,871			4,201	
General and administrative	125,358	69,187	18,762	12,586	101,098	17,723
Accretion of asset retirement obligations	5,581	5,009	1,521	1,330	5,523	1,521
(Gain) loss on commodity derivatives	(29,294)	(34,905)	59,482	22,545	(29,311)	59,482
(Gain) loss on sale of property	(85,621)	(9,761)	(110)	(1,983)	3,927	
Other, net	649	502	(12)		649	(12)
Total costs and expenses	352,967	336,867	180,223	112,660	402,733	179,368
Operating income	222,056	60,001	10,605	9,521	153,335	10,803
Other income (expense)						
Interest expense, net	(69,250)	(33,238)	(34,052)	(9,370)	(64,981)	(20,776)
Amortization of investment premium		(194)				
Other, net	145	535	31	29	143	31
Total other income (expense)	(69,105)	(32,897)	(34,021)	(9,341)	(64,838)	(20,745)
Income tax benefit (expense)	(1,619)	(107)	(100)		(31,915)	3,565
Net income (loss)	$ 151,332	$ 26,997	$ (23,516)	$ 180	$ 56,582	$ (6,377)
Cash Flow Data:						
Net cash provided by operating activities	$ 277,823	$ 240,404	$ 103,941	$ 75,281		
Net cash used in investing activities	367,443	606,738	308,361	86,312		
Net cash provided by financing activities	117,950	361,761	166,218	91,570		
Balance Sheet Data (at period end):						
Working capital (deficit)	$ 48,256	$ 63,054	$ (36,811)			(64,569)
Total assets	2,829,161	2,459,304	3,039,091			2,940,622
Total debt	1,663,217	939,382	1,927,931			1,608,786

Total equity (including noncontrolling interests)	858,132	1,276,709	742,313	861,144

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	MRD Segment				MRD Segment Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31,	Three Months Ended March 31,
	2013	2012	2014	2013	2013	2014
			(unaudited) (in thousands)		(unaudited)	
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$230,751	$138,032	$ 89,618	$ 54,038	$ 212,603	$ 89,060
Other revenues	807	782	248	124		149
Total revenues	231,558	138,814	89,866	54,162	212,603	89,209
Costs and expenses:						
Lease operating	25,006	24,438	5,709	5,077	23,354	6,119
Exploration	1,226	7,337	140	629	1,226	140
Production and ad valorem taxes	9,362	7,576	3,000	3,406	8,485	2,974
Depreciation, depletion and amortization	87,043	62,636	30,127	23,084	76,524	29,817
Impairment of proved oil and gas properties	2,527	18,339			128	
General and administrative	81,758	38,414	8,804	5,273	57,498	7,765
Accretion of asset retirement obligations	728	632	164	185	670	164
(Gain) loss on commodity derivatives	(3,013)	(13,488)	12,716	9,476	(3,030)	12,716
(Gain) loss on sale of property	(82,773)	(2)	(110)		6,775	
Other, net	2	364			2	
Total costs and expenses	121,866	146,246	60,550	47,130	171,632	59,695
Operating income	109,692	(7,432)	29,316	7,032	40,971	29,514
Other income (expense)						
Interest expense, net	(27,349)	(12,802)	(17,974)	(2,828)	(23,080)	(4,698)
Earnings from equity investments	1,066	4,880			269	6
Other, net	145	535	(2,955)	(2,120)	143	31
Total other income (expense)	(26,138)	(7,387)	(20,929)	(4,948)	(22,668)	(4,661)
Income tax (expense) benefit	(1,311)	178	(25)		(6,645)	(8,961)
Net income (loss)	$ 82,243	$ (14,641)	$ 8,362	$ 2,084	$ 11,658	$ 15,892
Cash Flow Data (Unaudited):						
Net cash provided by operating activities	$ 83,910	$ 84,172	$ 55,917	$ 33,762		
Net cash used in investing activities	5,533	230,471	83,962	32,635		
Net cash provided by (used in) financing activities	(38,963)	133,271	1,246	58,902		
Other Financial Data:						
Adjusted EBITDA (unaudited)	$ 197,903	$ 132,105	$ 71,188	$ 50,759	$ 159,239	$ 67,104
Balance Sheet Data (at period end):						
Working capital (deficit) (unaudited)	$ 51,214	$ 2,424	$ 15,914			(11,844)
Total assets	1,281,134	1,102,406	1,311,286			1,168,444
Total debt	871,150	309,200	939,496			620,351
Total equity (unaudited)	279,412	682,644	225,035			299,493

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 predecessor s consolidated and combined financial statements found 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

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by investors to measure our ability to meet debt service requirements. The following table provides a reconciliation of our pro forma MRD Segment net income to our pro forma MRD Segment Adjusted EBITDA.

Calculation of Adjusted EBITDA MRD Segment Pro Forma

	Year Ended December 31, 2013	Three Months Ended March 31, 2014
Net income (loss)	$ 11,658	$ 15,892
Interest expense, net	23,080	4,698
Income tax expense (benefit)	6,645	8,961
Depreciation, depletion and amortization	76,524	29,817
Impairment of proved oil and gas properties	128	
Accretion of AROs	670	164
(Gain) loss on commodity derivative instruments	(3,030)	12,716
Cash settlements received (paid) on commodity derivative instruments	12,257	(5,220)
(Gain) loss on sale of properties	6,775	
Acquisition related costs	1,584	
Incentive unit-based compensation expense	22,635	
Exploration costs	1,226	140
Non-cash equity (income) loss from MEMP	(1,050)	(117)
Cash distributions from MEMP	137	53
Adjusted EBITDA	$ 159,239	$ 67,104

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 NSAI, and the probable and possible reserve estimates were prepared by our management and audited by NSAI. Regarding our properties, estimates comprising 100% of the total proved reserves in the reserve report were prepared 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 Operations as well as Management s Discussion and Analysis of Financial Condition and Results of Operations and the summaries of our reserve report included herein as Appendix B-1 and Appendix B-2 in evaluating the material presented below.

Reserve Data

Estimated Proved Reserves		As of December 31, 2013
Natural gas (MMcf)		802,254
Oil/Condensate (MBbls)		11,311
NGLs (MBbls)		42,577
Total estimated net proved reserves (MMcfe)		1,125,577
Proved developed producing (MMcfe)		323,351
Proved developed non-producing (MMcfe)		44,290
Proved undeveloped (MMcfe)		757,936
Proved developed reserves as a percentage of total proved reserves		33%
PV-10 of proved reserves (in millions)(1)	$	1,469

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Estimated Probable Reserves(2)		
Natural Gas (MMcf)		535,185
Oil/Condensate (MBbls)		10,480
NGLs (MBbls)		33,709
Total estimated net probable reserves (MMcfe)		800,317
PV-10 of probable reserves (in millions)(1)	$	1,052
Estimated Possible Reserves(2)		
Natural Gas (MMcf)		1,080,539
Oil/Condensate (MBbls)		36,376
NGLs (MBbls)		68,686
Total estimated net possible reserves (MMcfe)		1,710,913
PV-10 of possible reserves (in millions)(1)	$	2,386

(1) PV-10 is a non-GAAP financial measure and differs from standardized measure, the most directly comparable GAAP financial measure. Please see Reserves.
(2) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

Production and Operating Data

	Historical MRD Segment(1)				MRD Segment Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31,	Three Months Ended March 31,
	2013	2012	2014	2013	2013	2014
Production and operating data:						
Oil (MBbls)	665	369	232	172	523	226
NGLs (MBbls)	1,457	898	515	272	1,454	515
Natural gas (MMcf)	34,092	24,130	10,674	8,037	33,205	10,674
Total (MMcfe)	46,819	31,731	15,155	10,697	45,066	15,119
Average net production (MMcfe/d)	128.3	86.7	168.4	118.9	123.5	168.0
Average sales price:						
Oil (per Bbl)	$ 100.76	$ 95.56	$ 95.05	$ 95.82	$ 100.15	$ 95.20
NGLs (per Bbl)	36.99	40.78	$ 41.00	$ 39.13	36.93	$ 41.00
Natural gas (per Mcf)	3.22	2.74	$ 4.35	$ 3.35	3.21	$ 4.35
Average price per Mcfe	$ 4.93	$ 4.35	$ 5.91	$ 5.05	$ 4.73	$ 5.89
Average unit costs per Mcfe:						
Lease operating expenses	$ 0.53	$ 0.77	$ 0.38	$ 0.47	$ 0.52	$ 0.41
Production and ad valorem taxes	$ 0.20	$ 0.24	$ 0.20	$ 0.32	$ 0.19	$ 0.20
General and administrative(2)	$ 1.75	$ 1.21	$ 0.58	$ 0.49	$ 1.27	$ 0.51
Depletion, depreciation and amortization	$ 1.86	$ 1.97	$ 1.99	$ 2.16	$ 1.69	$ 1.97

(1) Includes production and operating data for BlueStone, Golden Energy and Classic Pipeline, which will not be contributed to us in connection with the closing of this offering. The MRD Segment Pro Forma production and operating data has been adjusted to exclude the production and operating data for BlueStone and Classic Pipeline.
(2) Includes $0.92 and $0.30 per Mcfe of incentive unit compensation expense for the historical MRD Segment for the years ended December 31, 2013 and 2012 and $0.07 per Mcfe of incentive unit compensation expense for the three months ended March 31, 2014. The pro forma general and administrative expense for the year ended December 31, 2013 includes $0.50 per Mcfe of incentive unit compensation expense.

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RISK FACTORS

Investing in our common stock involves a high degree of risk. You should carefully consider the risks and uncertainties described below, as well as other information contained in this prospectus, before investing in our common stock. If any of the following risks actually occur, our business, financial condition, operating results or cash flow could be materially and adversely affected.

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 properties depend primarily on prevailing commodity prices. Historically, oil and natural gas prices have been volatile and fluctuate in response to changes in supply and demand, market uncertainty, and other factors that are beyond our control, including:

- the regional, domestic and foreign supply of oil, natural gas and NGLs;
- the level of commodity prices and expectations about future commodity prices;
- the level of global oil and natural gas exploration and production;
- localized supply and demand fundamentals, including the proximity and capacity of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;
- the cost of exploring for, developing, producing and transporting reserves;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;

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

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For example, for the five years ended December 31, 2013, the NYMEX-WTI oil future price ranged from a high of $113.93 per Bbl to a low of $33.98 per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $7.50 per MMBtu to a low of $1.82 per MMBtu. Any 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.

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NGLs comprised 23% of our estimated proved reserves at December 31, 2013 and accounted for 21% of our production on a volume equivalent basis for the three months ended March 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 NYMEX or ICE, 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 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. We depend on the services of certain former management members of WildHorse Resources for supervising and managing our drilling operations in the Terryville Complex, and in connection with the closing of the offering, we will enter into a services agreement with an entity managed by them for these same services. See Certain Relationships and Related Party Transactions Services Agreement. Under certain circumstances, this agreement may be terminated by the parties thereto and we may be unable to find replacement services, which could materially and adversely affect our ability to execute our plans for the development of the Terryville Complex. 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 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 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.

Significantly lower oil prices, or sustained lower natural gas prices, would 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 new revolving credit facility and our ability to finance planned or desired capital expenditures or acquisitions.

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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;

- 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.

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.

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;
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to, the following:

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

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

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

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

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

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2013, we had 10,825 gross (6,985 net) acres scheduled to expire in 2014, 20,078 gross (12,015 net) acres scheduled to expire in 2015, 31,215 gross (20,875 net) acres scheduled to expire in 2016 and 28,228 gross (19,649 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 2014 and 2015, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy 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.

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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, 2013, 10 gross (9.4 net) wells were in various stages of 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 2011 through December 31, 2013, we have drilled 83 gross (51.9 net) wells and, out of these wells, 3 gross (1.5 net) 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.

As of December 31, 2013, we had identified 1,582 gross (1,091 net) horizontal drilling locations on our existing acreage. Only 145 of these gross identified drilling locations had proved undeveloped reserves attributed to them in our reserve report. These drilling locations, including those with attributed proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these 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 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.

A majority of our 1,431 gross horizontal drilling locations within the Terryville Complex are identified within four distinct zones, with such gross horizontal drilling locations being roughly evenly distributed amongst such four zones. To date, we have drilled 27 horizontal wells within the key formations in Terryville Complex. Accordingly, we 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. Please see Business Our Operations Drilling Locations for more information on our gross identified drilling locations.

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, 2013 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. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. 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 and crews and can lead to shortages of, and increasing costs for, development equipment, 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 thus the results of our operations.

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 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, we expect that our new revolving credit facility will limit 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 the derivative contract and, accordingly, prevent us from realizing the benefit of the 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.

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 PV-10 of our estimated proved, probable and possible reserves 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, probable and possible reserves shown in this report, or PV-10, may not be the current market value of our estimated natural gas and oil reserves. In accordance

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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 and East Texas, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in North Louisiana and East Texas. At December 31, 2013, 99% of our total estimated proved reserves and for the three months ended March 31, 2014, 97% of our net average daily production were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, 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.

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. 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.

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.

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***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 have established a capital budget for 2014 of approximately $312 million and we intend to rely on cash flow from operating activities 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 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.

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, 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 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 that establish Prevention of

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Significant Deterioration, or PSD, and Title V permit reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet best available control technology standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which includes certain of our operations. In addition, in August 2012, the EPA established new source performance standards for volatile organic compounds and sulfur dioxide and an air toxic standard for oil and natural gas production, transmission, and storage. The rules include the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several other sources, such as storage tanks and other equipment, and limits methane emissions from these sources in an effort to reduce GHG emissions.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. In any event, the Obama administration has announced its Climate Action Plan, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and gas industry. As part of the Climate Action Plan, the Obama Administration also announced that it intends to adopt additional regulations to reduce emissions of GHGs and to encourage greater use of low carbon technologies in the coming years. 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 listing of a species as either threatened or endangered under the federal Endangered Species Act (ESA) 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 ESA and analogous state laws regulate a variety of activities that may have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. 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 presence of these 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 many 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 Position Limit Rule.

We qualify as a non-financial entity for purposes of the End-User Exception and, as such, we will be eligible for and expect to utilize such exception and, as a result, our hedging activity will not be 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. The 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 Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that a position limit rule is ultimately effected, 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.

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, in October 2011, the EPA announced its plan to propose 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. Proposed rules are expected sometime in 2014. 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 is scheduled to end on August 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. In September 2013, the EPA issued an amendment extending compliance dates for certain storage vessels. The EPA s final rule includes NSPS standards for completions of hydraulically fractured wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The rule is designed to limit emissions of volatile organic compounds, or VOCs, sulfur dioxide, and hazardous air pollutants from a variety of sources within natural gas processing plants, oil and natural gas production facilities, and natural gas transmission compressor stations. The EPA s rule requires the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of green completions for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. Under the rule, green completions will be phased in, and are not mandatory until January 2015. This rule could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface.

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

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comment and review in late 2014 with the final report expected to be completed sometime in 2016. 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, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

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 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 initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The 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.

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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. Following the restructuring transactions, MRD Holdco will own 5,360,912 subordinated units representing a 8.7% limited partner interest in MEMP. The remainder of the outstanding limited partner interests in MEMP are common units owned by public unitholders. 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, our 50% 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 and subordinated 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 March 31, 2014, Mr. Weinzierl, our Chief Executive Officer, owns 359,925 MEMP common units; Mr. Scarff, our President, owns 1,538 MEMP common units; Mr. Cozby, our Vice President and Chief Financial Officer, owns 101,837 MEMP common units; Mr. Forney, our Vice President, Operations, owns 92,447 MEMP common units; Mr. Roane, our Vice President, General Counsel and Corporate Secretary, owns 47,930 MEMP common units; and Mr. Robbins, our Vice President, Corporate Development, owns 53,801 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.

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

We have, and after the consummation of this offering will continue to have, a substantial amount of indebtedness. As of March 31, 2014, on a pro forma basis and after giving effect to this offering, the transactions described in Restructuring Transactions and the application of the net proceeds therefrom, we would have had aggregate indebtedness of approximately $620.4 million at the MRD Segment. The terms and conditions governing our indebtedness:

- 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.

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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.

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 and from our subsidiaries 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 new 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 currently restrict, and we expect our new revolving credit facility will 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.

Risks Relating to this Offering and Our Common Stock

There is no existing market for our common stock, and we do not know if one will develop, which could impede your ability to sell your shares and may depress the market price of our common stock.

There has not been a public market for our common stock prior to this offering. We cannot predict the extent to which investor interest in us will lead to the development of an active trading market or how liquid that market might become. If an active trading market does not develop, you may have difficulty selling any of our common stock that you buy. The initial public offering price for the common stock will be determined by negotiations between us, MRD Holdco and the underwriters and may not be indicative of prices that will prevail in the open market following this offering. See Underwriting. Consequently, you may be unable to sell our common stock at prices equal to or greater than the price you pay in this offering.

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

MRD Holdco, certain former management members of WildHorse Resources and our directors and executive officers have entered into lock-up agreements with respect to their common stock, pursuant to which they are subject to certain resale restrictions for a period of 180 days following the date of this prospectus. Citigroup Global Markets Inc., at any time, may release all or any portion of the common stock subject to the foregoing lock-up agreements. If the restrictions under the lock-up agreements are waived, then common stock will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

NGP has the ability to direct the voting of more than a majority of our common stock, and its interests may conflict with those of our other stockholders.

Upon completion of this offering, NGP, through the Funds, will beneficially own all of MRD Holdco, which will own in the aggregate approximately 55.8% of the combined voting power of our common stock (or approximately 52.4% if the underwriters option to purchase additional shares of common stock from MRD Holdco is exercised in full). In connection with the completion of this offering, MRD Holdco and certain former management members of WildHorse Resources (which former management members will own in the aggregate approximately 22.0% of the combined voting power of our common stock) will enter into a voting agreement, pursuant to which, they will agree, among other things, to vote all of their shares as directed by MRD Holdco. As a result, MRD Holdco and, thus, NGP will be able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of

NGP with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. Given this concentrated ownership, NGP would have to approve any potential acquisition of us. In addition, certain of our directors are currently employees of NGP. These directors duties as employees of NGP may conflict with their duties as our directors, and the resolution of these conflicts may not always be in our or your best interest.

Many of the directors and all of the officers who have responsibility for our management have significant duties with, and spend significant time serving, entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

All of our officers hold similar positions with MRD Holdco and MEMP GP, and many of our directors, who are responsible for managing the direction of our operations and acquisition activities, hold positions of responsibility with other entities (including NGP-affiliated entities) that are in the business of identifying and acquiring oil and natural gas properties. For example, the Funds and their affiliates (including NGP) are in the business of investing in oil and natural gas companies with independent management teams that also seek to acquire oil and natural gas properties, and MRD Holdco and MEMP are both in the business of acquiring and developing oil and natural gas properties. Mr. Hersh, one of our directors, is a managing partner of NGP; Mr. Gieselman, one of our directors, is a managing director of NGP; Mr. Weber, one of our directors, is a managing partner of NGP and serves as Chief Operating Officer for NGP; Mr. Innamorati, one of our directors, is a director of MEMP GP, and Mr. Weinzierl, our Chief Executive Officer and one of our directors, is the Chief Executive Officer and Chairman of MEMP GP, and was a managing director and operating partner of NGP and continues to hold ownership interests in the Funds and certain of their affiliates. Our officers will continue to devote significant time to the business of MEMP and MRD Holdco and face conflicts in allocating their time on our behalf and on behalf of MEMP GP and MRD Holdco. Our officers have also historically received a significant portion of their overall compensation in MEMP unit awards under the long term incentive plan of MEMP GP. We cannot assure you that any conflicts that may arise between us and our stockholders, on the one hand, and MRD Holdco, MEMP, or the Funds, on the other hand, will be resolved in our favor. The existing positions held by these directors and officers may give rise to fiduciary or other duties that are in conflict with the duties they owe to us. These officers and directors may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, they may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present those opportunities to us. These conflicts may not be resolved in our favor. For additional discussion of our management s business affiliations and the potential conflicts of interest of which our stockholders should be aware, see Certain Relationships and Related Party Transactions.

The corporate opportunity provisions in our amended and restated certificate of incorporation could enable NGP, MRD Holdco or the Funds to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our amended and restated certificate of incorporation, among other things:

- permits any of NGP, MRD Holdco, the Funds, their respective affiliates, or our officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and

- provides that if NGP, MRD Holdco, the Funds or their respective affiliates or any director or officer of one of our affiliates, NGP, MRD Holdco, the Funds or their respective affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

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As a result, NGP, MRD Holdco, the Funds or their affiliates may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to NGP, MRD Holdco or the Funds and their affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours. Please read Description of Capital Stock.

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

Upon the closing of this offering, MRD Holdco and certain former management members of WildHorse Resources, as a group, will continue to control a majority of our voting common stock. As a result, we will be a controlled company within the meaning of applicable corporate governance standards. Under the NASDAQ rules, a company of which more than 50% of the voting power is held by an individual, group or another company is a controlled company and may elect not to comply with certain corporate governance requirements, including:

- the requirement that we have a majority of independent directors on our Board;
- the requirement that we have a nominating committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities;
- the requirement that we have a compensation committee that is composed entirely of independent directors; and
- the requirement for an annual performance evaluation of the nominating and compensation committees.

Following this offering, we intend to utilize the foregoing exemptions from the applicable corporate governance requirements. As a result, we will not have a majority of independent directors and will not have a compensation committee. See Management. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the applicable corporate governance requirements.

The price of our common stock may fluctuate significantly and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- changes in earnings estimates or recommendations by securities analysts who track our common stock or industry;

- market and industry perception of our success, or lack thereof, in pursuing our growth strategy; and

- sales of common stock by us, our stockholders (including the Funds), or members of our management team.

In addition, the stock market has experienced significant price and volume fluctuations in recent years. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industries. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with us, and these fluctuations could materially reduce our share price.

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We currently have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

We currently have no plans to pay regular dividends on our common stock. Any payment of dividends in the future will be at the discretion of our Board and will depend on, among other things, our earnings, financial condition and business opportunities, the restrictions in our debt agreements, and other considerations that our Board deems relevant. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

We may sell additional shares of common stock in subsequent public offerings or otherwise, including to finance acquisitions. Our amended and restated certificate of incorporation which we will adopt in connection with the closing of this offering will authorize us to issue 600,000,000 shares of common stock, of which 192,500,000 shares will be outstanding upon consummation of this offering. The outstanding share number includes shares that we and MRD Holdco are selling in this offering, which may be resold immediately in the public market. The remaining outstanding shares are restricted from immediate resale under the lock-up agreements with the underwriters described in Underwriting, but may be sold into the market in the near future. Following the expiration of the applicable lock-up period, which is 180 days after the date of this prospectus, 149,700,000 shares of our common stock may be sold into the public market, subject to compliance with the Securities Act or exemptions therefrom. See Shares Eligible for Future Sale for a discussion of the shares of our common stock that may be sold into the public market in the future.

MRD Holdco and certain former management members of WildHorse Resources will be party to the Registration Rights Agreement, which will require us to effect the registration of their shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement entered into in connection with this offering. Upon the effectiveness of such a registration statement, all shares covered by the registration statement would be freely transferable without restriction or further registration under the Securities Act, except for any such shares which are acquired by any of our affiliates as that term is defined in Rule 144 under the Securities Act, which will be subject to the resale limitations of Rule 144. See Certain Relationships and Related Party Transactions Registration Rights Agreement.

As soon as practicable after this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of 19,250,000 shares of our common stock issued or reserved for issuance under our Memorial Resource Development Corp. 2014 Long Term Incentive Plan that we plan to adopt prior to the completion of this offering. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under our registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

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

Our organizational documents and the voting agreement may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our amended and restated certificate of incorporation, our amended and restated bylaws to be effective upon the completion of this offering and the voting agreement may make it more difficult for, or prevent a third party from, acquiring control of us. These provisions include:

requiring that certain former management members of WildHorse Resources vote all of their shares of our common stock, including with respect to the election of our directors, as directed by MRD Holdco;

at such time MRD Holdco, NGP or as the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, our Board will be divided into three classes with each class serving staggered three year terms;

at such time MRD Holdco, NGP or as the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, any action by stockholders may only be taken at an annual meeting or special meeting and may no longer be effected by a written consent of the stockholders, subject to the rights of any series of preferred stock with respect to such rights;

at such time as MRD Holdco, NGP or the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, special meetings of our stockholders may only be called by our Board pursuant to a resolution adopted by the affirmative vote of a majority of the total number of authorized directors whether or not there exist any vacancies in previously authorized directorships (prior to such time, a special meeting may also be called at the request of stockholders holding a majority of the outstanding shares entitled to vote);

at such time as MRD Holdco, NGP or the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, the affirmative vote of the holders of at least 75% in voting power of all then outstanding common stock entitled to vote generally in the election of directors, voting together as a single class, shall be required to remove any or all of the directors from office at any time;

prohibiting cumulative voting in the election of directors; and

authorizing the issuance of blank check preferred stock without any need for action by stockholders.

Our issuance of shares of preferred stock could delay or prevent a change in control of us. Our Board has authority to issue shares of preferred stock without stockholder approval in one or more series, designate the number of shares constituting any series, and fix the rights, preferences, privileges and restrictions thereof, including dividend rights, voting rights, rights and terms of redemption, redemption price or prices and liquidation preferences of such series. The issuance of shares of our preferred stock may have the effect of delaying, deferring or preventing a change in control without further action by the stockholders, even where stockholders are offered a premium for their shares.

Together, our amended and restated certificate of incorporation, amended and restated bylaws and the voting agreement could make the removal of management more difficult and may discourage transactions that otherwise could involve payment of a premium over prevailing market prices for our common stock. Furthermore, the existence of the foregoing provisions, as well as the significant amount of common stock beneficially owned by the Funds following this offering, could limit the price that investors might be willing to pay in the future for shares of our common stock. They could also deter potential acquirers of us, thereby reducing the likelihood that you could receive a premium for your common stock in an acquisition. See Description of Capital Stock Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, our Amended and Restated Bylaws and Delaware Law.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies, as described under the caption Certain Relationships and Related Party Transactions. The resolution of any conflicts that may arise in connection with any related party transactions that we have entered into with MEMP, NGP, MRD Holdco, the Funds or their affiliates, including pricing, duration or other terms of service, may not always be in our or our stockholders best interests because NGP or the Funds may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, please read NGP has the ability to direct the voting of more than a majority of our common stock, and its interests may conflict with those of our other stockholders.

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You will experience an immediate and substantial dilution in the net tangible book value of the common stock you purchase.

After giving effect to this offering and the other adjustments described in Dilution, we expect that our pro forma as adjusted net tangible book value as of March 31, 2014 would be $3.14 per share. You will experience immediate and substantial dilution of approximately $15.86 per share in net tangible book value of the common stock you purchase in this offering. See Dilution, including the discussion of the effects on dilution from a change in the price of this offering.

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

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

The additional requirements of having a class of publicly traded equity securities may strain our resources and distract management.

After the consummation of this offering, we will be subject to additional reporting requirements of the Securities and Exchange Act of 1934 (the Exchange Act), the Sarbanes-Oxley Act of 2002 and the Dodd-Frank Act. The Dodd-Frank Act effects comprehensive changes to public company governance and disclosures in the United States and will subject us to additional federal regulation. We cannot predict with any certainty the requirements of the regulations ultimately adopted or how the Dodd-Frank Act and such regulations will impact the cost of compliance for a company with publicly traded common stock. We are currently evaluating and monitoring developments with respect to the Dodd-Frank Act and other new and proposed rules and cannot predict or estimate the amount of the additional costs we may incur or the timing of such costs. These laws, regulations and standards are subject to varying interpretations, in many cases due to their lack of specificity, and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. This could result in continuing uncertainty regarding compliance matters and higher costs necessitated by ongoing revisions to disclosure and governance practices. We intend to invest resources to comply with evolving laws, regulations and standards, and this investment may result in increased general and administrative expenses and a diversion of management s time and attention from revenue-generating activities to compliance activities. If our efforts to comply with new laws, regulations and standards differ from the activities intended by regulatory or governing bodies due to ambiguities related to practice, regulatory authorities may initiate legal proceedings against us and our business may be harmed. We also expect that being a company with publicly traded common stock and these new rules and regulations will make it more expensive for us to obtain director and officer liability insurance, and we may be required to accept reduced coverage or incur substantially higher costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our Board, particularly to serve on our audit committee, and qualified executive officers.

The Sarbanes-Oxley Act requires that we maintain effective disclosure controls and procedures and internal control over financial reporting. These requirements may place a strain on our systems and resources. Under Section 404 of the Sarbanes-Oxley Act, we will be required to include a report of management on our internal control over financial reporting in our Annual Reports on Form 10-K beginning with the Form 10-K for the year ending December 31, 2014. In order to maintain and improve the effectiveness of our disclosure controls and

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procedures and internal control over financial reporting, significant resources and management oversight will be required. This may divert management s attention from other business concerns, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. If we are unable to conclude that our disclosure controls and procedures and internal control over financial reporting are effective, or if we are no longer an emerging growth company and our independent public accounting firm is unable to provide us with an unqualified report on our internal control over financial reporting in future years, investors may lose confidence in our financial reports and our stock price may decline.

We will remain an emerging growth company for up to five years. After we are no longer an emerging growth company, we expect to incur significant additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not emerging growth companies, including Section 404 of the Sarbanes-Oxley Act. Please read We will incur increased costs as a result of being a public company, which may significantly affect our financial condition.

We will incur increased costs as a result of being a public company, which may significantly affect our financial condition.

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

We are an emerging growth company and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors.

We are an emerging growth company, as defined in the JOBS Act, and we intend to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. We intend to take advantage of these reporting exemptions until we are no longer an emerging growth company. We cannot predict if investors will find our common stock less attractive because we will rely on these exemptions. If some investors find our common stock less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

We will cease to be an emerging growth company upon the earliest of (i) the last day of the fiscal year in which we have $1.0 billion or more in annual revenues, (ii) 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), (iii) the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period, or (iv) 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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To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, our shareholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common stock.

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

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements. Forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, are forward-looking statements. When used in this prospectus, the words could, should, will, believe, anticipate, intend, estimate, expect, may, continue, pre pursue, target, project, forecast, the negative of such terms, or other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about:

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

competition;

government regulations;

marketing of production;

exploitation or property acquisitions;

costs of exploiting and developing our properties and conducting other operations;

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;

taxation of the oil and natural gas industry;

developments in other countries that produce oil and natural gas;

uncertainty regarding future operating results;

plans and objectives of management; and

plans, objectives, expectations and intentions contained in this prospectus that are not historical.

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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. 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:

- 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 new 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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USE OF PROCEEDS

We estimate that we will receive net proceeds from this offering of approximately $382.1 million, after deducting underwriting discounts and commissions and fees and expenses associated with this offering and the restructuring transactions of $26.4 million payable by us.

The following table illustrates our use of proceeds of this offering and borrowings under our new revolving credit facility:

Sources of Cash (In millions)		**Uses of Cash (In millions)**	
Net proceeds from this offering	$ 382.1	Redemption of PIK notes(1)	$ 359.9
Borrowings under our new revolving credit facility	616.7	Cash consideration to certain former management members of WildHorse Resources(2)	30.0
		Repayment of outstanding borrowings under WildHorse Resources credit agreements(2)	587.4
		Reimbursement to MRD LLC for June 15 interest payment on the PIK notes(2)	17.2
		Costs associated with our new revolving credit facility	4.3
Total	$ 998.8	Total	$ 998.8

(1) Includes the payment of principal plus any applicable premium and accrued and unpaid interest, if any, to the date of redemption, which we expect will be 30 days after the closing of this offering. Until such redemption date or any earlier discharge date, we will use the amount to be paid to the holders of the PIK notes to temporarily reduce amounts outstanding under our new revolving credit facility.

(2) Please see Restructuring Transactions for additional discussion of the cash consideration that will be paid to certain former management members of WildHorse Resources and the reimbursement to MRD LLC and Management Discussion and Analysis of Financial Condition and Results of Operations Debt Agreements MRD Segment WildHorse Resources Revolving Credit Facility and Second Lien Facility (To Be Terminated at Closing) for a description of the repayment of outstanding borrowings under WildHorse Resources credit agreements that will be made in connection with the restructuring transactions. $587.4 million represents the aggregate outstanding borrowings under the WildHorse Resources credit agreements as of May 30, 2014.

We will not receive any proceeds from the sale of shares of our common stock by MRD Holdco, including pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock. MRD Holdco is deemed under federal securities laws to be an underwriter with respect to the common stock it may sell in connection with this offering.

The PIK notes bear interest at the rate of 10.00% per annum if paid in cash and 10.75% per annum if paid as PIK interest and mature on December 15, 2018. MRD LLC used the net proceeds from the offering of the PIK notes after paying offering expenses to repay all amounts outstanding under its senior secured credit facility, to fund a debt service reserve account for the payment of interest on the PIK notes, to pay a distribution to the Funds and for general company purposes. In connection with the closing of this offering, we will enter into a new revolving credit facility and use a portion of the borrowings under that agreement to repay outstanding borrowings under WildHorse Resources credit agreements, which will be terminated upon repayment. Borrowings under WildHorse Resources credit agreements were used to acquire assets, to make capital expenditures and for other general corporate purposes. See Management s Discussion and Analysis of Financial Condition and Results of Operations Debt Agreements MRD Segment.

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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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CAPITALIZATION

The following table shows our predecessor s cash and cash equivalents and our predecessor s capitalization as of March 31, 2014:

- on an actual basis; and

- on a pro forma basis as adjusted to give effect to (i) the restructuring transactions described under Restructuring Transactions, including borrowing $620.4 million under our new revolving credit facility to repay outstanding borrowings under WildHorse Resources credit agreements and (ii) the issuance and sale of 21,500,000 shares of common stock in this offering by us at an initial offering price of $19.00 per share and our application of the net proceeds as described under Use of Proceeds.

You should read this table together with Restructuring Transactions, Use of Proceeds, and Management s Discussion and Analysis of Financial Condition and Results of Operations and the pro forma and historical consolidated financial statements included elsewhere in this prospectus. For a description of the pro forma adjustments, please read our Unaudited Pro Forma Combined Financial Statements.

	At March 31, 2014	
	Actual	Pro Forma As Adjusted
Cash and cash equivalents(1)	$ 39,519	36,444
Restricted cash(2)	50,003	
Long-term debt:		
MRD Segment:		
WildHorse Resources revolving credit facility	271,100	
WildHorse Resources second lien term loan	325,000	
MRD senior secured revolving credit facility		620,351
10.00%/10.75% Senior PIK Toggle Notes due 2018	343,396	
MEMP Segment:		
MEMP revolving credit facility	299,000	299,000
7.625% senior notes due 2021	689,435	689,435
Total long-term debt	1,927,931	1,608,786
Members equity:		
MRD LLC members equity	222,889	
Stockholders equity:		
Common stock, $0.01 par value, 1,000 shares authorized, 100 shares issued and outstanding (historical); 600,000,000 shares authorized, 192,500,000 shares issued and outstanding		1,925
Additional paid-in capital		1,172,170
Accumulated deficit		(870,261)
Total Memorial Resource Development Corp. stockholders equity		303,834
Noncontrolling interest	519,424	557,310
Total capitalization	2,670,244	2,469,930

(1) Includes $1.7 million of cash and cash equivalents related to MEMP and its subsidiaries.
(2) Represents the $50 million of restricted cash held in the debt service reserve account related to, including as security for payment of interest and certain other payments on, the PIK notes of which $32.8 million (net of approximately $17.2 million to be used to pay accrued interest on the PIK notes on June 15, 2014 is to be retained by MRD LLC in the restructuring transactions and released to MRD Holdco upon redemption of the PIK notes (which we expect will be 30 days after the closing of this offering). We will reimburse MRD LLC for the approximately $17.2 million interest payment with borrowings under our new revolving credit facility.

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of the common stock to be sold in this offering exceeds the net tangible book value (deficit) per share of common stock after the offering. Net tangible book value per share is determined at any date by subtracting our total liabilities from the total book value of our tangible assets and dividing the difference by the number of shares of common stock deemed to be outstanding at that date. There will be 19,250,000 shares of our common stock reserved for future awards under the Memorial Resource Development Corp. 2014 Long Term Incentive Plan as of the consummation of this offering.

Our net tangible book value as of March 31, 2014 was $222.9 million, or $1.31 per share. After giving effect to the receipt of approximately $382.1 million of estimated net proceeds from our sale of 21,500,000 shares of common stock in this offering and 1,068,421 restricted shares of common stock to be issued by us to our independent directors and certain of our employees in connection with the successful completion of this offering pursuant to our Plan (see Management Executive Compensation Compensation Following This Offering IPO Bonuses.), our as adjusted net tangible book value as of March 31, 2014 would have been approximately $605.0 million, or $3.14 per share. This represents an immediate increase in our net tangible book value of $1.83 per share to our existing stockholders and an immediate dilution of $15.86 per share to new investors purchasing shares of common stock in the offering. The following table illustrates this substantial and immediate per share dilution to new investors:

	Per Share
Initial public offering price per share	$ 19.00
Net tangible book value before the offering	1.31
Increase per share attributable to investors in the offering	1.83
As adjusted net tangible book value after the offering	3.14
Dilution per share to new investors	$ 15.86

The following table summarizes on an as adjusted basis as of March 31, 2014, giving effect to:

- the total number of shares of common stock purchased from us;
- the total consideration paid to us (before deducting the underwriting discounts and commissions and estimated offering expenses payable by us in connection with this offering); and
- the average price per share paid by our existing stockholders and by new investors purchasing shares in this offering:

	Shares Purchased		Total Consideration		
	Number	Percent	(in thousands) Amount	Percent	Average Price Per Share
Existing stockholders(1)	171,000,000	89%	$ 223,440	35%	$ 1.31
Investors in the offering	21,500,000	11%	408,500	65%	19.00

Total	192,500,000	100%	$ 631,940	100%	$ 3.28

(1) The number of shares disclosed for the existing stockholders includes 27,720,000 shares that may be sold by MRD Holdco in this offering, including pursuant to any exercise of the underwriters option to purchase additional shares of common stock.

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SELECTED HISTORICAL FINANCIAL DATA

MRD LLC and its consolidated subsidiaries, our accounting predecessor, controls MEMP through its ownership of MEMP GP, the general partner of MEMP. Because MRD LLC controls MEMP through its ownership of the general partner, MRD LLC is required to consolidate MEMP for accounting and financial reporting purposes even though MRD LLC owns a minority of its partner interests and MRD LLC and MEMP have independent capital structures. MRD LLC receives cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP. In connection with the closing of this offering, MRD LLC will contribute substantially all of its existing assets to us in exchange for shares of our common stock. Through our ownership of MEMP GP, we will continue to control MEMP and therefore will continue to consolidate the results of MEMP into our consolidated financial statements in future periods.

Our predecessor has two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

MRD reflects all of MRD LLC s consolidating subsidiaries except for MEMP and its subsidiaries.

MEMP reflects the consolidated and combined operations of MEMP and its subsidiaries.

We will continue to have two reportable segments following the completion of this offering. For more information regarding reportable business segments, please see the predecessor s audited historical financial statements and related notes and our predecessor s unaudited historical interim financial statements included elsewhere in this prospectus.

The following tables include the selected historical financial data of our predecessor, as well as the MRD Segment as of and for the periods indicated. The selected historical financial data of our predecessor as of and for the years ended December 31, 2013 and 2012 were derived from the audited historical financial statements of our predecessor included elsewhere in this prospectus. The selected historical financial data of our predecessor as of March 31, 2014 and for the three months ended March 31, 2014 and 2013 were derived from the unaudited interim financial statements of our predecessor included elsewhere in this prospectus. The selected historical financial data of the MRD Segment as of and for the years ended December 31, 2013 and 2012 were derived from certain financial information used in the preparation of our predecessor s audited financial statements. The selected historical financial data for the MRD Segment as of March 31, 2014 and for the three months ended March 31, 2014 and 2013 were derived from certain financial information used in the preparation of our predecessor s unaudited interim financial statements.

The selected unaudited pro forma data as of and for the three months ended March 31, 2014 and for the year ended December 31, 2013 has been prepared to give pro forma effect to: (i) the exclusion of BlueStone and Classic Pipeline, the MEMP subordinated units and the debt service account associated with the PIK notes, which are not being conveyed to us in connection with this offering, as well as our reimbursement for the June 15, 2014 interest payment on the PIK notes, (ii) the offering of our shares of common stock contemplated hereby and the use of the net proceeds therefrom as described in Use of Proceeds, (iii) incremental federal income tax expense, and (iv) the restructuring transactions.

We derived the data in the following tables from, and the following tables should be read together with and is qualified in its entirety by reference to, our predecessor s historical financial statements and our pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read Restructuring Transactions, Use of Proceeds, Management s Discussion and Analysis of Financial Condition and Results of Operations, and our pro forma and historical consolidated financial statements, all included elsewhere in this prospectus. Among other things, those historical consolidated and combined financial statements and pro forma financial statements include more detailed information regarding the basis of presentation for the following data.

	MRD LLC (Predecessor)				Memorial Resource Development Corp. Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31,	Three Months Ended March 31,
	2013	2012	2014	2013	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 571,948	$ 393,631	$ 189,917	$ 121,626	$ 553,800	$ 189,359
Other revenues	3,075	3,237	911	555	2,268	812
Total revenues	575,023	396,868	190,828	122,181	556,068	190,171
Costs and expenses:						
Lease operating	113,640	103,754	33,682	26,364	111,988	34,092
Pipeline operating	1,835	2,114	489	470	1,835	489
Exploration	2,356	9,800	146	856	2,356	146
Production and ad valorem taxes	27,146	23,624	8,584	7,286	26,269	8,558
Depreciation, depletion and amortization	184,717	138,672	57,679	43,206	174,198	57,369
Impairment of proved oil and gas properties	6,600	28,871			4,201	
General and administrative	125,358	69,187	18,762	12,586	101,098	17,723
Accretion of asset retirement obligations	5,581	5,009	1,521	1,330	5,523	1,521
(Gain) loss on commodity derivatives	(29,294)	(34,905)	59,482	22,545	(29,311)	59,482
(Gain) loss on sale of property	(85,621)	(9,761)	(110)	(1,983)	3,927	
Other, net	649	502	(12)		649	(12)
Total costs and expenses	352,967	336,867	180,223	112,660	402,733	179,368
Operating income	222,056	60,001	10,605	9,521	153,335	10,803
Other income (expense)						
Interest expense, net	(69,250)	(33,238)	(34,052)	(9,370)	(64,981)	(20,776)
Amortization of investment premium		(194)				
Other, net	145	535	31	29	143	31
Total other income (expense)	(69,105)	(32,897)	(34,021)	(9,341)	(64,838)	(20,745)
Income tax benefit (expense)	(1,619)	(107)	(100)		(31,915)	3,565
Net income (loss)	$ 151,332	$ 26,997	$ (23,516)	$ 180	$ 56,582	$ (6,377)
Cash Flow Data:						
Net cash provided by operating activities	$ 277,823	$ 240,404	$ 103,941	$ 75,281		
Net cash used in investing activities	367,443	606,738	308,361	86,312		
Net cash provided by financing activities	117,950	361,761	166,218	91,570		
Balance Sheet Data (at period end):						
Working capital (deficit)	$ 48,256	$ 63,054	$ (36,811)			(64,569)
Total assets	2,829,161	2,459,304	3,039,091			2,940,622
Total debt	1,663,217	939,382	1,927,931			1,608,786
Total equity (including noncontrolling interests)	858,132	1,276,709	742,313			861,144

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	MRD Segment				MRD Segment Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31,	Three Months Ended March 31,
	2013	2012	2014	2013	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 230,751	$ 138,032	$ 89,618	$ 54,038	$ 212,603	$ 89,060
Other revenues	807	782	248	124		149
Total revenues	231,558	138,814	89,866	54,162	212,603	89,209
Costs and expenses:						
Lease operating	25,006	24,438	5,709	5,077	23,354	6,119
Exploration	1,226	7,337	140	629	1,226	140
Production and ad valorem taxes	9,362	7,576	3,000	3,406	8,485	2,974
Depreciation, depletion and amortization	87,043	62,636	30,127	23,084	76,524	29,817
Impairment of proved oil and gas properties	2,527	18,339			128	
General and administrative	81,758	38,414	8,804	5,273	57,498	7,765
Accretion of asset retirement obligations	728	632	164	185	670	164
(Gain) loss on commodity derivatives	(3,013)	(13,488)	12,716	9,476	(3,030)	12,716
(Gain) loss on sale of property	(82,773)	(2)	(110)		6,775	
Other, net	2	364			2	
Total costs and expenses	121,866	146,246	60,550	47,130	171,632	59,695
Operating income	109,692	(7,432)	29,316	7,032	40,971	29,514
Other income (expense)						
Interest expense, net	(27,349)	(12,802)	(17,974)	(2,828)	(23,080)	(4,698)
Earnings from equity investments	1,066	4,880			269	6
Other, net	145	535	(2,955)	(2,120)	143	31
Total other income (expense)	(26,138)	(7,387)	(20,929)	(4,948)	(22,668)	(4,661)
Income tax (expense) benefit	(1,311)	178	(25)		(6,645)	(8,961)
Net income (loss)	$ 82,243	$ (14,641)	$ 8,362	$ 2,084	$ 11,658	$ 15,892
Cash Flow Data (Unaudited):						
Net cash provided by operating activities	$ 83,910	$ 84,172	$ 55,917	$ 33,762		
Net cash used in investing activities	5,533	230,471	83,962	32,635		
Net cash provided by (used in) financing activities	(38,963)	133,271	1,246	58,902		
Other Financial Data:						
Adjusted EBITDA (unaudited)	$ 197,903	$ 132,105	$ 71,188	$ 50,759	$ 159,239	$ 67,104
Balance Sheet Data (at period end):						
Working capital (deficit) (unaudited)	$ 51,214	$ 2,424	$ 15,914			(11,844)
Total assets	1,281,134	1,102,406	1,311,286			1,168,444
Total debt	871,150	309,200	939,496			620,351
Total equity (unaudited)	279,412	682,644	225,035			299,493

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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 the 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 described under the heading Risk Factors included elsewhere in this prospectus. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. Also see Cautionary Note Regarding Forward-Looking Statements included elsewhere in this prospectus.

Overview

We are a Delaware corporation formed by Memorial Resource Development LLC (MRD LLC) in January 2014 to own and acquire oil and natural gas properties in North America. MRD LLC is 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).

In connection with the closing of this offering, MRD LLC and its consolidated subsidiaries, which is our accounting predecessor, will contribute to us substantially all of its assets, comprised of the following, in exchange for shares of common stock: (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 will contribute to us the remaining 0.1% membership interest in WildHorse Resources as well as exchange their incentive units in exchange for shares of common stock and cash consideration. At that time, we will be majority-owned by the group consisting of MRD Holdco LLC (MRD Holdco) and certain former management members of WildHorse Resources.

Following the completion of the offering, MRD LLC will retain and distribute 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 (iii) the $32.8 million in cash (net of approximately $17.2 million to be used to pay PIK note interest on June 15, 2014) to be released from its debt service reserve account in connection with the redemption of the PIK notes (which we expect will be 30 days after the closing of this offering) 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 will reimburse MRD LLC for the approximately $17.2 million interest payment with borrowings under our new revolving credit facility.

After the closing of the redemption of the PIK notes and the termination of the PIK notes indenture (which will occur approximately 30 days after the closing date of this offering unless discharged earlier), MRD LLC will merge into MRD Operating LLC. Until the date of such merger, MRD LLC will perform under its current commercial contracts for our benefit, all amounts received under such contracts will be for our benefit and we will be responsible for all amounts owing under such contracts. At the time MRD LLC merges into MRD Operating LLC, MRD LLC s sole assets will be commercial contracts entered into in the ordinary course of business and relating to the businesses owned by us.

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Prior to this offering MRD LLC controlled, and after this offering we will 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 MRD LLC s control of MEMP through the ownership of its general partner, MRD LLC is required to consolidate MEMP for accounting and financial reporting purposes. Although consolidated for accounting and financial reporting, MRD LLC and MEMP have independent capital structures. MRD LLC receives cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP.

Business Segments

MRD LLC has two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

MRD reflects all of MRD LLC s consolidating subsidiaries except for MEMP and its subsidiaries.

MEMP reflects the consolidated and combined operations of MEMP and its subsidiaries.

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. For additional information regarding this financial measure, see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA. For additional information regarding our predecessor s reportable business segments, see the notes to our predecessor s consolidated and combined financial statements found elsewhere in this prospectus.

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 on October 1, 2013;

acquisition by MEMP of all the outstanding membership interests in Prospect Energy, LLC for a purchase price of approximately $16.3 million on October 1, 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 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.

The MRD Segment is focused on the exploitation, development, and acquisition of natural gas, NGL and oil properties mainly in the Cotton Valley formation in North Louisiana and East Texas as well as the Rocky Mountains. 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 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 principally located in East Texas/North Louisiana, the Permian Basin, offshore Southern California, the Rockies, the Eagle Ford and South Texas. 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.

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Recent Developments

MRD Segment

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. The repurchase of the net profits interests was accounted for as a combination of entities under common control at historical cost in a manner similar to the pooling of interest method and our consolidated and combined financial statements presented herein have been retrospectively revised. As WildHorse Resources is the operator of the properties and sold the net profits interest to the affiliate of NGP in 2010, these net profits interests are accounted for as working interests in our consolidated and combined financial statements.

On April 1, 2014, WildHorse Resources sold certain oil and natural gas properties in East Texas to MEMP for approximately $34.0 million in cash consideration, subject to customary post-closing adjustments.

On May 9, 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, subject to customary post-closing adjustments.

MEMP Segment

On March 25, 2014, MEMP acquired certain oil and natural gas properties in the Eagle Ford trend from Alta Mesa Holdings, LP for a purchase price of $173.0 million, subject to customary purchase price adjustments. The acquired properties are 100% non-operated.

On April 1, 2014, MEMP acquired certain oil and natural gas properties in East Texas from WildHorse Resources for approximately $34.0 million in cash consideration, subject to customary post-closing adjustments.

On May 5, 2014, MEMP entered into a purchase and sale agreement with Merit Energy Company, LLC and certain of its affiliates to acquire oil and natural gas liquids properties in Wyoming for an aggregate purchase price of approximately $935 million, subject to customary purchase price adjustments.

Sources of Revenues

Both the MRD Segment s and the MEMP Segment 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 their 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 segments intend to periodically enter into derivative contracts with respect to a significant portion of their estimated natural gas and oil production through various transactions that fix the future prices received. These transactions may include price swaps whereby the applicable segment will receive a fixed price for production and pay a variable market price to the contract counterparty. Additionally, either segment may enter into costless collars, whereby the applicable segment receives the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. 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 the MRD and MEMP Segments take full advantage of all credits and exemptions in the various taxing jurisdictions where they 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 unproved and proved properties. For unproved properties, these primarily include costs associated with lease expirations. 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, explore and develop natural gas, NGLs and oil. As a successful efforts company, all costs associated with acquisition and development efforts and all successful exploration efforts are capitalized, and these costs are allocated to each unit of production using the units of production method.

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 incentive units, franchise taxes, audit and other professional fees, and legal compliance expenses. Certain of our and our predecessor s employees hold incentive units in MRD LLC and/or, prior to the restructuring transactions, certain subsidiaries of MRD LLC, that may, upon vesting, entitle the holders to a disproportionate share of future distributions by MRD LLC to its members after all of the members that have made capital contributions to MRD LLC and/or certain subsidiaries have received cumulative distributions in respect of their membership interest equal to specified rates of return.

In connection with the closing of this offering, certain former management members of WildHorse Resources will contribute 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. We expect that approximately $0.5 million, which is the portion of the total consideration related to acquiring the 0.1% membership interest, will be accounted for as the acquisition of noncontrolling interests and approximately $833.8 million will be recorded in compensation expense within general and administrative expenses during the second quarter of 2014 related to the incentive units. The compensation expense related to the shares of our common stock, which is approximately $804.4 million, will be offset by a deemed capital contribution from MRD Holdco.

In connection with the restructuring transactions, the MRD LLC incentive units will be exchanged for substantially identical units in MRD Holdco, and such incentive units will 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 within general and administrative expenses, which may be material, in the period in which the performance conditions are probable of being satisfied. The compensation expense recognized by us related to the incentive units will be offset by a deemed capital contribution from MRD Holdco.

Interest expense. Both the MRD and MEMP Segments finance a portion of their working capital requirements and acquisitions with borrowings under revolving credit facilities and senior note issuances. As a result, both the MRD and MEMP Segments 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. MRD LLC, our predecessor, is a limited liability company not subject to federal income taxes. Accordingly, no provision for federal income taxes has been provided for in our historical results of operations because taxable income was passed through to MRD LLC s members. Although we are a corporation under the Internal Revenue Code, subject to federal income taxes at a statutory rate of 35% of pretax earnings, we do not expect to report any income tax benefit or expense until the consummation of this offering.

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Results of Operations

Consolidated

Selected consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the three months ended March 31, 2014 and 2013 are presented below and have been derived from our predecessor s consolidated and combined financial statements included elsewhere in this prospectus. Also see our predecessor s consolidated and combined financial statements and related notes included elsewhere in this prospectus for a description of our predecessor s previous owners.

	For Year Ended December 31, 2013	2012	For Three Months Ended March 31, 2014	2013
	(in thousands)			
			(unaudited)	
Oil & natural gas sales	$ 571,948	$ 393,631	$ 189,917	$ 121,626
Lease operating	113,640	103,754	33,682	26,364
Exploration	2,356	9,800	146	856
Production and ad valorem taxes	27,146	23,624	8,584	7,286
Depreciation, depletion, and amortization	184,717	138,672	57,679	43,206
Impairment of proved oil and natural gas properties	6,600	28,871		
General and administrative	125,358	69,187	18,762	12,586
(Gain) loss on commodity derivative instruments	(29,294)	(34,905)	59,482	22,545
(Gain) loss on sale of properties	(85,621)	(9,761)	(110)	(1,983)
Interest expense, net	69,250	33,238	34,052	9,370
Net income (loss)	151,332	26,997	(23,516)	180

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

Our predecessor recorded net income of $151.3 million in 2013 compared to net income of $27.0 million in 2012. The increase in net income was primarily due to increases in revenues and gains on the sale of properties, partially offset by increases in DD&A, general and administrative expenses and interest expense.

Oil and natural gas revenues were $571.9 million, an increase of $178.3 million from 2012. Production increased 28,062 MMcfe (approximately 37%) while the average realized sales price increased $0.31 per Mcfe. Production increases were primarily due to acquisitions and drilling activities in North Louisiana and East Texas. The favorable volume variance contributed to a $147.2 million increase in revenues and the favorable pricing variance contributed to a $31.1 million increase in revenues.

The $46.0 million increase in DD&A expense was primarily due to increased production volumes related to acquisitions and drilling activities in North Louisiana and East Texas. Increased production volumes increased DD&A expense by $51.8 million, while a 3% decrease in the DD&A rate between periods decreased DD&A expense by $5.8 million.

During 2013, BlueStone sold its remaining interests in certain properties in East Texas to a third party and recognized a gain of $89.5 million. This gain was partially offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain of its Wyoming properties. During 2012, the previous owners of oil and gas properties acquired by MEMP recognized a gain of approximately $9.8

million related to the sale of properties in West Texas.

Interest expense was $69.3 million in 2013, an increase of $36.0 million from 2012. The increase in interest expense was primarily due to higher levels of indebtedness as debt outstanding was $939.4 million at December 31, 2012 compared to $1,663.2 million at December 31, 2013.

Please see segment discussion below for further information regarding changes in other line items on a segment basis.

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Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013

Our predecessor recorded a net loss of $23.5 million for the three months ended March 31, 2014 compared to net income of $0.2 million for the three months ended March 31, 2013. Increased losses on commodity derivatives, increased interest expense, increased lease operating expenses, increased DD&A, and increased general and administrative expenses more than offset the increase in oil and natural gas sales.

Oil and natural gas revenues were $189.9 million, an increase of $68.3 million from 2013. Production increased 7,794 MMcfe (approximately 35%) while the average realized sales price increased $0.86 per Mcfe. Production increases were primarily due to acquisitions and drilling activities in North Louisiana and East Texas. The favorable volume variance contributed to a $42.5 million increase in revenues and the favorable pricing variance contributed to a $25.8 million increase in revenues.

Lease operating expenses were $33.7 million and $26.4 million for the three months ended March 31, 2014 and 2013, respectively. During 2014, MEMP recorded $2.9 million of estimated environmental remediation expenses associated with its Permian and Wyoming oil and gas properties.

The $14.5 million increase in DD&A expense was primarily due to increased production volumes related to acquisitions and drilling activities in North Louisiana and East Texas. Increased production volumes increased DD&A expense by $15.0 million, while a 1% decrease in the DD&A rate between periods decreased DD&A expense by $0.5 million.

General and administrative expenses for the three months ended March 31, 2014 were $18.8 million and included $2.3 million of non-cash unit-based compensation expense and $1.9 million of acquisition-related costs. General and administrative expenses for the three months ended March 31, 2013 totaled $12.6 million and included $0.4 million of non-cash unit-based compensation expense and $0.3 million of acquisition-related costs. Increased salaries and employee count also contributed to increased general and administrative expenses between periods.

Net losses on commodity derivative instruments of $59.5 million were recognized during the three months ended March 31, 2014, consisting of $13.2 million of cash settlement payouts in addition to a $46.3 million decline in the fair value of open hedge positions. Net losses on commodity derivative instruments of $22.5 million were recognized during the three months ended March 31, 2013, consisting of $11.1 million of cash settlement receipts, which were offset by a $33.6 million decrease in the fair value of open hedge positions.

Interest expense was $34.1 million in the three months ended March 31, 2014, an increase of $24.7 million from 2013. The increase in interest expense was primarily due to higher levels of indebtedness. The mix of debt was also a contributing factor. The PIK notes and MEMP s Senior Notes carry a higher interest rate compared to debt under revolving credit facilities.

Please see segment discussion below for further information regarding changes in other line items on a segment basis.

MRD Segment

The MRD Segment s consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the three months ended March 31, 2014 and 2013 presented below have been derived from our predecessor s consolidated and combined financial statements included elsewhere in this prospectus. Please see the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for information regarding business segments. The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- the sale by BlueStone of substantially all of its assets in July 2013 for approximately $117.9 million, which resulted in the recognition of a $89.5 million gain;

- the acquisition of oil and gas properties by WildHorse Resources in Louisiana in March 2013 for approximately $67.1 million; and

- the acquisition by WildHorse Resources of oil and gas properties in East Texas and North Louisiana in May 2012 for a net purchase price of approximately $77.5 million.

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In addition to the transactions affecting comparability of the results of operations of the MRD Segment among the periods presented, the results of operations of the MRD Segment following the completion of this offering will be affected by incremental public company expenses and general and administrative costs.

In connection with the closing of this offering and the restructuring transactions, we will acquire substantially all of MRD LLC s assets other than BlueStone, MRD Royalty, MRD Midstream, Golden Energy, Classic Pipeline, the MEMP subordinated units and the remaining cash held in the debt service reserve account established in connection with the issuance of the PIK notes. Collectively, at March 31, 2014, these excluded assets represented approximately 3% of total consolidated assets and approximately 11% of MRD Segment total assets, respectively. Total revenues for the three months ended March 31, 2014 for these excluded assets were approximately 1% of total consolidated revenues and approximately 3% of MRD Segment total revenues, respectively.

	For Year Ended December 31, 2013	2012	For Three Months Ended March 31, 2014	2013
	(in thousands)		(unaudited)	
Oil & natural gas sales	$ 230,751	$ 138,032	$ 89,618	$ 54,038
Lease operating	25,006	24,438	5,709	5,077
Exploration	1,226	7,337	140	629
Production and ad valorem taxes	9,362	7,576	3,000	3,406
Depreciation, depletion, and amortization	87,043	62,636	30,127	23,084
Impairment of proved oil and natural gas properties	2,527	18,339		
General and administrative	81,758	38,414	8,804	5,273
(Gain) loss on commodity derivative instruments	(3,013)	(13,488)	12,716	9,476
(Gain) loss on sale of properties	(82,773)	(2)	(110)	
Interest expense, net	27,349	12,802	17,974	2,828
Net income (loss)	82,243	(14,641)	8,362	2,084
Natural gas and oil revenue:				
Oil sales	$ 66,961	$ 35,264	$ 22,023	$ 16,450
NGL sales	53,881	36,611	21,120	10,628
Natural gas sales	109,909	66,157	46,475	26,960
Total natural gas and oil revenue	$ 230,751	$ 138,032	$ 89,618	$ 54,038
Production Volumes:				
Oil (MBbls)	665	369	232	172
NGLs (MBbls)	1,457	898	515	272
Natural gas (MMcf)	34,092	24,130	10,674	8,037
Total (MMcfe)	46,819	31,731	15,155	10,697
Average net production (MMcfe/d)	128.3	86.7	168.4	118.9
Average sales price:				
Oil (per Bbl)	$ 100.76	$ 95.56	$ 95.05	$ 95.82
NGL (per Bbl)	36.99	40.78	41.00	39.13
Natural gas (per Mcf)	3.22	2.74	4.35	3.35
Total (Mcfe)	$ 4.93	$ 4.35	$ 5.91	$ 5.05

Average unit costs per Mcfe:								
Lease operating expense	$	0.53	$	0.77	$	0.38	$	0.47
Production and ad valorem taxes	$	0.20	$	0.24	$	0.20	$	0.32
General and administrative expenses	$	1.75	$	1.21	$	0.58	$	0.49
Depletion, depreciation, and amortization	$	1.86	$	1.97	$	1.99	$	2.16

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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 15,088 MMcfe (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.

Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes.

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.

General and administrative expenses were $81.8 million in 2013, an increase of $43.3 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 and incentive unit compensation expense. General and administrative expenses during 2013 included recognition of approximately $43.3 million of compensation expense related to an incentive unit payments to certain key management members of certain MRD LLC subsidiaries compared to approximately $9.5 million recorded in 2012.

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.

Given the volatility of commodity prices, it is not possible to predict future changes in fair value or cash settlements that will ultimately be realized upon settlement of the open positions in future years. If commodity prices at settlement are lower than the prices of the settled positions, the derivative contracts are expected to mitigate the otherwise negative effect on earnings of lower oil, natural gas and NGL prices. However, if commodity prices at settlement are higher than the prices of the settled positions, the derivative contracts are expected to dampen the otherwise positive effect on earnings of higher oil, natural gas and NGL prices and will, in this context, be viewed as having resulted in an opportunity cost.

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.

Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013

The MRD Segment recorded net income of $8.4 million for the three months ended March 31, 2014 compared to net income of $2.1 million for the three months ended March 31, 2013. The increase in net income was primarily due to both increased production and average sales price for natural gas, offset by an increase in interest expense.

Oil and natural gas revenues were $89.6 million for the three months ended March 31, 2014, an increase of $35.6 million from the same period in 2013. Production increased 4,458 MMcfe (approximately 42%) and average realized sales price increased $0.86 per Mcfe. Production volume increases were primarily due to drilling activities in the Cotton Valley in North Louisiana and East Texas and from contributions from acquisitions. The favorable volume variance contributed to a $22.5 million increase in revenues and the favorable pricing variance contributed to a $13.1 million increase in revenues.

Lease operating expenses were $5.7 million for the three months ended March 31, 2014, an increase of $0.6 million from the same period in 2013. On a per Mcfe basis, lease operating expenses decreased by $0.09 per Mcfe as certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges.

The increase in DD&A expense was primarily due to increased production volumes related to acquisitions in 2013, as well as from drilling activities in the Cotton Valley in North Louisiana and East Texas. Increased production volumes caused DD&A expense to increase by $9.6 million and the 8% decrease in the DD&A rate between periods caused DD&A expense to decrease by $2.6 million. On a per Mcfe basis, DD&A expense decreased by $0.17 per Mcfe. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base.

General and administrative expenses were $8.8 million in the three months ended March 31, 2014, an increase of $3.5 million from the three months ended March 31, 2013. The increase in general and administrative expenses was primarily due to growth in employees as a result of acquisitions and development activities and incentive unit compensation expense. General and administrative expenses during the three months ended March 31, 2014 included recognition of approximately $1.0 million of compensation expense related to incentive unit payments made by BlueStone. No compensation expense related to incentive unit payments was recognized during the comparable period.

Net losses on commodity derivative instruments of $12.7 million were recognized during the three months ended March 31, 2014, consisting of $5.2 million of cash settlement payouts in addition to a $7.5 million decline in the fair value of open hedge positions. Net losses on commodity derivative instruments of $9.5 million were recognized during the three months ended March 31, 2013, consisting of $4.0 million of cash settlement receipts, which were offset by a $13.5 million decrease in the fair value of open hedge positions.

Net interest expense during the three months ended March 31, 2014 was $18.0 million, including amortization of deferred financing fees of approximately $1.5 million and losses on interest rate swaps of $0.2 million. Net interest expense during the three months ended

March 31, 2013 was $2.8 million, including amortization of deferred financing fees of approximately $0.3 million and losses on interest rate swaps of less than $0.1 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including the $350.0 million of PIK notes issued in December 2013 and the $325.0 million second lien term facility at WildHorse Resources incurred during June 2013.

MEMP Segment

The MEMP Segment s consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the three months ended March 31, 2014 and 2013 presented below have been derived from MRD LLC s 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 net purchase price of approximately $126.9 million;

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; and

multiple 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.

	For Year Ended December 31,		For Three Months Ended March 31,	
	2013	2012	2014	2013
	(in thousands)			
			(unaudited)	
Oil & natural gas sales	$ 341,197	$ 255,608	$ 100,299	$ 67,588
Lease operating	88,893	80,116	27,988	21,371
Exploration	1,130	2,463	6	227
Production and ad valorem taxes	17,784	16,048	5,584	3,880
Depreciation, depletion, and amortization	97,269	76,036	26,745	20,391
Impairment of proved oil and natural gas properties	54,362	10,532		
General and administrative	43,495	30,342	9,958	7,313
(Gain) loss on commodity derivative instruments	(26,281)	(21,417)	46,766	13,069
(Gain) loss on sale of properties	(2,848)	(9,759)		(1,983)
Interest expense, net	41,901	20,436	16,078	6,542
Net income (loss)	20,268	46,518	(34,057)	(4,297)
Natural gas and oil revenue:				
Oil sales	$ 171,095	$ 145,103	$ 41,795	$ 34,237
NGL sales	51,215	26,647	13,767	9,665
Natural gas sales	118,887	83,858	44,737	23,686
Total natural gas and oil revenue	$ 341,197	$ 255,608	$ 100,299	$ 67,588
Production Volumes:				
Oil (MBbls)	1,764	1,519	453	373
NGLs (MBbls)	1,632	745	420	288
Natural gas (MMcf)	35,924	29,744	9,712	7,647

Total (MMcfe)	56,303	43,329	14,952	11,614
Average net production (MMcfe/d)	154.3	118.4	166.1	129.0
Average sales price:				
Oil (per Bbl)	$ 96.98	$ 95.54	$ 92.28	$ 91.78
NGL(per Bbl)	31.38	35.75	32.74	33.54
Natural gas (per Mcf)	3.31	2.82	4.61	3.10
Total (Mcfe)	$ 6.06	$ 5.90	$ 6.71	$ 5.82
Average unit costs per Mcfe:				
Lease operating expense	$ 1.58	$ 1.85	$ 1.87	$ 1.84
Production and ad valorem taxes	$ 0.32	$ 0.37	$ 0.37	$ 0.33
General and administrative expenses	$ 0.77	$ 0.70	$ 0.67	$ 0.63
Depletion, depreciation, and amortization	$ 1.73	$ 1.75	$ 1.79	$ 1.76

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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 2012.

Oil and natural gas revenues were $341.2 million in 2013, an increase of $85.6 million from 2012. Production increased 12,974 MMcfe (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 $1.7 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.

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.

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Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013

MEMP recorded a net loss of $34.1 million for the three months ended March 31, 2014 compared to a net loss of $4.3 million for the three months ended March 31, 2013. Increased losses on commodity derivatives, increased interest expense, increased lease operating expenses, and increased DD&A more than offset the increase in oil and natural gas sales.

Oil, natural gas and NGL revenues for the three months ended March 31, 2014 totaled $100.3 million, an increase of $32.7 million compared with 2013. Production increased 3,338 MMcfe (approximately 29%), primarily from new drills in East Texas and increased volumes from third party acquisitions. The average realized sales price increased $0.89 per Mcfe primarily due to higher gas prices. The favorable volume and pricing variance contributed to an approximate $19.4 million and $13.3 million increase in revenues, respectively.

Lease operating expenses were $28.0 million and $21.4 million for the three months ended March 31, 2014 and 2013, respectively. On a per Mcfe basis, lease operating expenses increased to $1.87 for 2014 from $1.84 for 2013. During the three months ended March 31, 2014, MEMP recorded $2.9 million of estimated environmental remediation expenses associated with its Permian and Wyoming oil and gas properties.

Production and ad valorem taxes for the three months ended March 31, 2014 totaled $5.6 million, an increase of $1.7 million compared with the three months ended March 31, 2013 primarily due to an increase in production volumes. On a per Mcfe basis, production and ad valorem taxes increased to $0.37 for the three months ended March 31, 2014 from $0.33 for 2013.

DD&A expense for the three months ended March 31, 2014 was $26.7 million compared to $20.4 million for the three months ended March 31, 2013, a $6.3 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to third party acquisitions consummated during 2013 and the Partnership s drilling program. Increased production volumes caused DD&A expense to increase by an approximate $5.8 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $0.5 million.

General and administrative expenses for the three months ended March 31, 2014 were $10.0 million and included $1.3 million of non-cash unit-based compensation expense and $1.9 million of acquisition-related costs. General and administrative expenses for the three months ended March 31, 2013 totaled $7.3 million and included $0.4 million of non-cash unit-based compensation expense and $0.2 million of acquisition-related costs. Increased salaries and employee count also contributed to increased general and administrative expenses between periods.

Net losses on commodity derivative instruments of $46.8 million were recognized during the three months ended March 31, 2014, consisting of $8.0 million of cash settlement payouts in addition to a $38.8 million decline in the fair value of open hedge positions. Net losses on commodity derivative instruments of $13.1 million were recognized during the three months ended March 31, 2013, consisting of $7.1 million of cash settlement receipts, which were offset by a $20.2 million decrease in the fair value of open hedge positions.

Net interest expense during the three months ended March 31, 2014 was $16.1 million, including amortization of deferred financing fees of approximately $0.8 million and losses on interest rate swaps of $0.3 million. Net interest expense during the three months ended March 31, 2013 was $6.5 million, including amortization of deferred financing fees of approximately $2.2 million and losses on interest rate swaps of less than $0.1 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including the MEMP Senior Notes issued in April, May and October 2013.

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Liquidity and Capital Resources

Although results are consolidated for financial reporting, the MRD and MEMP Segments operate with independent capital structures. With the exception of cash distributions paid to the MRD Segment by the MEMP Segment related to MEMP partnership interests held by MRD LLC, 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 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, 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, NGLs and oil properties. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet future financial obligations, planned capital expenditure activities and liquidity requirements. The future success in growing proved reserves and production will be highly dependent on the capital resources available. As of December 31, 2013, we had 1,582 identified gross potential horizontal well locations, which will take many years to develop. Additionally, the proved undeveloped reserves will require an estimated $1.3 billion of development capital over the next five years according to our reserve report as of December 31, 2013. A significant portion of this capital requirement will be funded out of operating cash flows. However, we may be required to generate or raise significant capital to conduct drilling activities on these identified potential well locations and to finance the development of proved undeveloped reserves.

We expect that the primary sources of liquidity and capital resources after the consummation of this offering will be cash flows generated by operating activities and borrowings under revolving credit facilities. We will also have the ability to issue additional equity and debt as needed through private or public offerings. We may from time to time (including during 2014) refinance our existing indebtedness including by issuing longer-term fixed rate debt to refinance shorter-term floating rate debt.

After the completion of this offering, we believe our cash flows provided by operating activities and availability under our 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 2014 development drilling activities. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices, 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.

Capital Budget

During 2013, we invested approximately $190 million of capital at the MRD Segment to drill 31 gross (21.3 net) wells. A substantial portion of our development program is focused on horizontal drilling of liquids rich wells in the Terryville Complex, where we spent approximately $163 million in capital expenditures to drill 15 gross (12.1 net) horizontal wells during 2013.

In 2014, we have budgeted a total of $312 million to drill and complete 46 gross (39 net) operated wells, which includes $83 million of capital expenditures we made during the three months ended March 31, 2014 (including $61 million of capital expenditures we made in the Terryville Complex). We expect to fund our 2014 development primarily from cash flows from operations. The majority of our drilling locations and our 2014 development program are focused on the Terryville Complex, where we plan to invest $264 million on drilling and completing 33 gross (28 net) horizontal wells and 2 gross (2.0 net) vertical wells. We plan to run four to five rigs during 2014 targeting primarily our four primary zones within the Cotton Valley the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. Total vertical depth of these zones ranges from 8,200 to 11,200 feet.

In our East Texas properties in the Joaquin Field, we plan to spend development capital of $36 million running one rig to drill 8 gross (6 net) horizontal wells targeting the Cotton Valley formation at vertical depths of 6,000 to 10,000 feet.

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In our Rockies properties, we plan to spend $12 million of development capital, primarily in the Tepee Field in the Piceance Basin in Colorado focused on completing 3 wells drilled in fourth quarter of 2013 and running 1 rig to drill an additional 3 operated wells.

Cash Flows from Operating, Investing and Financing Activities

The following tables summarize both consolidated/combined and 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 included elsewhere in this prospectus.

Consolidated & Combined

	For Year Ended December 31,		For Three Months Ended March 31,	
	2013	2012	2014	2013
			(unaudited)	
Net cash provided by operating activities	$ 277,823	$ 240,404	$ 103,941	$ 75,281
Net cash used in investing activities	367,443	606,738	308,361	86,312
Net cash provided by financing activities	117,950	361,761	166,218	91,570

MRD Segment

	For Year Ended December 31,		For Three Months Ended March 31,	
	2013	2012	2014	2013
	(unaudited)		(unaudited)	
Net cash provided by operating activities	$ 83,910	$ 84,172	55,917	33,762
Net cash used in investing activities:				
Acquisition of oil and natural gas properties	$ (67,098)	$ (83,055)		
Additions to oil and gas properties	(198,340)	(165,203)	(86,629)	(38,745)
Additions to other property and equipment	(2,432)	(1,267)	(31)	(32)
Equity investments in MEMP Segment	(521)	(206)		(180)
Distributions received from MEMP Segment related to partnership interests	26,006	19,263	3,002	6,322
Additions to restricted cash	(49,347)		(3)	
Proceeds from the sale of oil and gas properties to third parties	151,187			
Proceeds from the sale of MEMP common units	135,012			
Other		(3)	(301)	
Net cash provided by (used in) investing activities	$ (5,533)	$ (230,471)	$ (83,962)	$ (32,635)
Net cash provided by financing activities:				
Advances on revolving credit facilities	$ 174,400	$ 228,450	$ 108,000	$ 14,900
Payments on revolving credit facilities	(280,500)	(129,750)	(40,000)	(10,750)
Borrowings under second lien credit facility	325,000			
Proceeds from the issuance of PIK notes	343,000			
Loan origination fees	(20,267)	(1,276)	(895)	(39)
Purchase of noncontrolling interests in consolidated subsidiaries	(13,865)			
Contribution from NGP affiliate		7,033	1,165	
Contributions from MEMP Segment	180,260	29,280		55,419
Distributions to noncontrolling interest	(7,446)		(325)	

Distributions to MEMP Segment		(1,900)		
Distributions to NGP affiliates			(66,693)	
Distributions to Funds	(732,362)			
Distributions made by previous owners	(2,590)	(2,317)		(549)
Other cash transfers from MEMP Segment		3,751		
Other	(4,593)		(6)	(79)
Net cash provided by (used in) financing activities	$ (38,963)	$ 133,271	$ 1,246	$ 58,902

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 15,088 MMcfe (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.

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

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

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

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

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

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

In November 2013, MRD LLC purchased the noncontrolling interests in Black Diamond, Classic GP and Classic for $13.9 million of 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. From time to time, MRD LLC has made distributions of cash to the Funds. The timing and amount of these cash distributions is within the discretion of the board of managers of MRD LLC and is 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 $15.9 million in 2013 compared to $2.3 million in 2012.

Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013

Operating Activities. Net cash flows provided by operating activities were $55.9 million in the three months ended March 31, 2014 compared to $33.8 million in the three months ended March 31, 2013. Production increased 4,458 MMcfe (approximately 42%) and average realized sales price increased $0.86 per Mcfe as previously discussed under Results of Operations MRD Segment.

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Investing Activities. Total cash used in investing activities was $84.0 million in the three months ended March 31, 2014 compared to $32.6 million for the same period in 2013. Cash used for additions to oil and gas properties $86.6 million in the three months ended March 31, 2014 compared to $38.7 million for the same period in 2013, which consisted primarily of drilling and completion activities in the Cotton Valley in North Louisiana and East Texas area.

Distributions of $3.0 million were received from MEMP on the subordinated units owned by MRD LLC in the three months ended March 31, 2014 compared to $6.3 million in 2013 received from MEMP on the common and subordinated units owned by MRD LLC.

Financing Activities. Net advances under revolving credit facilities were $68.0 million in the three months ended March 31, 2014 compared to $4.1 million in the three months ended March 31, 2013. The 2014 net borrowings were primarily used by WildHorse Resources to repurchase net profits interests from an affiliate of NGP as discussed above under Recent Development MRD Segment. Distributions to NGP affiliates 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. MEMP paid $55.4 million to WildHorse Resources in connection with MEMP s March 28, 2013 acquisition of all the outstanding equity interests in WHT.

MEMP Segment

	For Year Ended December 31, 2013	For Year Ended December 31, 2012	For Three Months Ended March 31, 2014	For Three Months Ended March 31, 2013
		(unaudited)		(unaudited)
Net cash provided by operating activities	$ 193,697	$ 156,844	$ 48,023	$ 41,771
Net cash used in investing activities:				
Acquisition of oil and natural gas properties	$ (38,664)	$ (277,623)	$ (173,000)	$ (6,310)
Additions to oil and gas properties	(161,675)	(107,789)	(47,571)	(42,330)
Additions to other property and equipment	(238)	(1,748)		(69)
Additions to restricted investments	(5,361)	(4,599)	(826)	(1,281)
Proceeds from the sale of oil and gas properties	4,525	34,521		2,169
Other		29		285
Net cash used in investing activities	$ (201,413)	$ (357,209)	$ (221,397)	$ (47,536)
Net cash provided by financing activities				
Advances on revolving credit facilities	$ 958,355	$ 391,000	$ 235,000	$ 230,250
Payments on revolving credit facilities	(1,485,537)	(121,819)	(39,000)	(301,397)
Proceeds from the issuances of senior notes	688,563			
Loan origination fees	(20,908)	(2,225)	(267)	(1,670)
Contributions from previous owners	7,233	44,072		151
Contribution from NGP affiliate	2,013	38,125		
Contribution from general partner	521	206		180
Contributions from MRD Segment		1,900		
Net proceeds from public equity offering	490,138	194,304		172,321
Distributions to partners	(96,643)	(34,436)	(33,763)	(17,424)
Distributions to MRD Segment	(180,260)	(29,280)		(55,419)
Distributions to NGP affiliates	(355,495)	(242,174)		
Distributions made by previous owners	(2,552)	(26,455)		(717)
Other cash transfers to MRD Segment		(3,751)		

Other	(9,013)	(646)		
Net cash provided by (used in) financing activities	$ (3,585)	$ 208,821	$ 161,970	$ 26,275

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

Operating Activities. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. 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. For the years ended December 31, 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 compared to $194.3 million in 2012. In March 2013, MEMP issued 9,775,000 common units to the public at an offering price of $18.35 per unit generating net proceeds of approximately $171.8 million. In October 2013, MEMP issued 16,675,000 common units to the public at an offering price of $19.90 per unit generating net proceeds of approximately $318.3 million. In December 2012, MEMP generated net proceeds of $194.3 million from a public offering of common units.

MEMP completed a private placement of 7.625% senior notes due 2021 (the Senior Notes) with two additional issuances during 2013. MEMP issued $300.0 million aggregate principal amount of the Senior Notes at 98.521% of par in April 2013, an additional $100.0 million aggregate principal amount at 102.0% of par in May 2013 and an additional $300.0 million aggregate principal amount at 97.0% of par in October 2013. Total proceeds, net of discounts, from the issuance of the Senior Notes were $688.6 million during 2013.

Distributions to partners were $96.6 million during the year ended December 31, 2013 compared to $34.4 million during the year ended December 31, 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.

The previous owners received contributions of $7.2 million during 2013 compared to $44.1 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. 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.

Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013

Operating Activities. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Net income decreased by $29.8 million as further discussed above under Results of Operations MEMP Segment, and net cash provided by operating activities increased by $6.3 million. Net cash provided by operating activities included $8.1 million of cash settlements paid on derivative instruments during 2014 compared to $6.5 million of cash settlements received on derivative instruments during the three months ended March 31, 2013.

Investing Activities. Net cash used in investing activities during the three months ended March 31, 2014 was $221.4 million, of which $173.0 million was used to acquire oil and natural gas properties from a third parties and $47.6 million was used for additions to oil and gas properties. Cash used in investing activities during the three months ended March 31, 2013 was $47.5 million, of which $6.3 million was used to acquire oil and natural gas properties from a third party and $42.3 million was used for additions to oil and gas properties. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with our offshore Southern California oil and gas properties.

Financing Activities. On March 25, 2013, MEMP issued 9,775,000 common units representing limited partner interests in the Partnership (including 1,275,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the public at an offering price of $18.35 per unit generating gross proceeds of approximately $179.4 million, offset by approximately $7.1 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.

Distributions to partners during the three months ended March 31, 2014 were $33.8 million compared to $17.4 million during the same period in 2013, of which the MRD Segment received $3.0 million during the three months ended March 31, 2014 compared to $6.3 million in the three months ended March 31, 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.

MEMP paid $55.4 million to WildHorse Resources in connection with its March 28, 2013 acquisition of all of the outstanding equity interests in WHT and repaid $89.3 million of indebtedness under WHT s credit facility. MEMP had net borrowings of $37.0 million under its revolving credit facility during 2013 that were primarily used to fund the WHT acquisition. Tanos and the previous owners had aggregate advances of $12.3 million under their credit facilities and repaid an aggregate of $31.1 million of outstanding borrowings during the three months ended March 31, 2013. MEMP had net borrowings of $196.0 million under its revolving credit facility during the three months ended March 31, 2014 that were used primarily used to fund its Eagle Ford acquisition. Deferred financing costs of approximately $0.3 million were incurred during the three months ended March 31, 2014 compared to approximately $1.7 million during the three months ended March 31, 2013.

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Debt Agreements MRD Segment

New Revolving Credit Facility

Concurrently with the closing of this offering, we anticipate that we, as borrower, and certain of our current and future subsidiaries, as guarantors, will enter into a new senior secured revolving credit facility. We expect the new revolving credit facility to be a five-year, $2.0 billion revolving credit facility with an initial borrowing base of $725 million and aggregate elected commitments of $725 million.

We will be permitted to borrow under our new 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. Our new revolving credit facility will be reserve-based, and thus our borrowing base will be 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 will be 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 will be 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 our new 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 future 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 our new revolving credit facility.

Borrowings under the new revolving credit facility will be 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 under the new revolving credit facility will 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 will be subject to a commitment fee that varies from 0.375% to 0.50% per annum according to our total commitments usage.

Our new revolving credit facility will require maintenance of a ratio of Consolidated EBITDAX to Consolidated Net Interest Expense (as each term is determined under the new 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 new revolving credit facility, which we refer to as the current ratio, of not less than 1.0 to 1.0.

Additionally, the new revolving credit facility will contain 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.

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Events of default under the new revolving credit facility shall include, but not be 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 new revolving credit facility, together with accrued interest, fees and other obligations under the credit agreement, could be declared immediately due and payable.

MRD LLC Revolving Credit Agreement (Terminated) & PIK Notes (To Be Redeemed 30 Days After Closing)

On July 13, 2012, MRD LLC entered into a two-year $50.0 million senior secured revolving credit facility with an initial borrowing base of $35.0 million. MRD LLC pledged 7,061,294 MEMP common units and 5,360,912 MEMP subordinated units as security under the credit facility as well as its oil and gas properties and certain other assets of MRD LLC. On November 20, 2012, MRD LLC entered into a first amendment to its credit agreement, which among other things: (i) increased the aggregate maximum credit to $1.0 billion (ii) increased the borrowing base to $120.0 million and (iii) extended the maturity date to November 20, 2016. On April 25, 2013, MRD LLC entered into a second amendment to its credit agreement, which among other things: (i) increased the borrowing base to $170.0 million and (ii) designated Tanos together with its consolidating subsidiaries as additional guarantors.

On October 1, 2013, Tanos and its consolidating subsidiaries were removed as guarantors and the borrowing base was reduced to $120.0 million. On November 1, 2013, MRD LLC entered into a third amendment to its credit agreement, which among other things: (i) designated Black Diamond together with its consolidating subsidiaries as additional guarantors, (ii) reduced the borrowing base to $100.0 million, and (iii) permitted second lien indebtedness. On November 22, 2013, the borrowing base was automatically reduced to $60.0 million upon MRD LLC s sale of 7,061,294 MEMP common units in a secondary offering. On December 18, 2013, indebtedness then outstanding under the revolving credit facility of $59.7 million and all accrued interest were paid off in full and the revolving credit facility was terminated in connection with the issuance of the PIK notes discussed below.

On December 18, 2013, 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 and will mature on 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 is payable semi-annually in arrears on June 15 and December 15 of each year, commencing on June 15, 2014. Subject to conditions in the indenture governing the PIK notes, MRD LLC is required to pay interest on the PIK notes in cash or through issuing additional notes (such an issuance, PIK Interest). The interest rate on the PIK notes is 10.00% per annum for interest paid in cash or 10.75% per annum for PIK Interest. Any PIK Interest will be paid by issuing additional notes having the same terms as the PIK notes. PIK notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The MRD Issuers may also be required to repurchase the PIK notes upon a change of control.

At the time the PIK notes were issued, all of MRD LLC s subsidiaries other than MEMP and BlueStone and each of their respective subsidiaries were designated as restricted subsidiaries. The indenture governing the PIK notes contains customary covenants and restrictive provisions that apply to both MRD LLC and its restricted subsidiaries, many of which will terminate if at any time no default exists under the indenture and the PIK notes receive an investment grade rating from both of two specified ratings agencies. The PIK notes are fully and unconditionally guaranteed on a senior unsecured basis by all of MRD LLC s restricted subsidiaries, except MEMP GP and WildHorse Resources.

WildHorse Resources is party to credit arrangements (discussed below) consisting of a credit agreement and a second lien term loan, which credit arrangements impose significant restrictions on WildHorse Resources, including limitations on WildHorse Resources ability to distribute cash to MRD LLC. For example, distributions from WildHorse Resources to MRD LLC are subject to certain conditions under WildHorse Resources credit arrangements and are limited to the lesser of (i) 50% of WildHorse Resources net income from July 1, 2013 together with, among other things, capital contributions and returns on investments and (ii) the lesser of (x) 50% of WildHorse Resources net income for the four fiscal quarters preceding any such distribution and (y) $45,000,000. WildHorse Resources credit arrangements also include other restrictions, including restrictions on WildHorse Resources ability to enter into transactions with its affiliates, including MRD LLC.

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, all outstanding PIK 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 PIK notes may declare all the PIK notes to be due and payable immediately.

Contemporaneous with the closing of this offering, we will issue a redemption notice to the holders of the PIK notes pursuant to which we will redeem all outstanding PIK notes 30 days after the delivery of such notice. On the redemption date, we will pay all principal and any applicable premium and accrued and unpaid interest on such notes with a portion of the net cash proceeds of this offering. Until the redemption date or any earlier discharge date of the PIK notes, we will use the amount to be paid to the holders of those notes to temporarily reduce amounts outstanding under our new revolving credit facility. We will be subject to the provisions of the PIK notes indenture until the redemption date or any earlier discharge date. We will reimburse MRD LLC for the approximately $17.2 million of interest paid by MRD LLC in respect of the PIK notes on June 15th.

WildHorse Resources Revolving Credit Facility and Second Lien Facility (To Be Terminated At Closing)

On May 12, 2010, WildHorse Resources entered into a revolving credit facility. Borrowings under the amended revolving credit facility are 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 April 3, 2013, WildHorse Resources entered into an amended and restated credit agreement. The new revolving credit facility provides for aggregate maximum credit amounts at any time of $1.0 billion, consisting of borrowings and letters of credit and has an initial borrowing base of $300.0 million. The new revolving credit facility matures on April 13, 2018. The borrowing base is subject to redetermination on at least a semi-annual basis. Borrowings under the revolving credit facility are 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 matures on December 13, 2018. No amount of second lien term loans once repaid may be reborrowed. Borrowings bear 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 are 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 is set forth in an intercreditor agreement. The second lien term loan agreement contains 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 one-time special $225.0 million distribution to MRD LLC. This $225.0 million distribution was subsequently distributed to the Funds.

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In connection with the closing of this Offering, we anticipate that the WildHorse Resources revolving credit facility and second lien term loan will be repaid in full and terminated.

Black Diamond Revolving Credit Facility (Terminated)

On July 27, 2011, the Black Diamond entered into a second amended and restated revolving credit facility, which extended the maturity date of the original agreement to May 9, 2015. Borrowings under the revolving credit facility are collateralized by Black Diamond s oil and natural gas properties. On November 1, 2013, the Black Diamond revolving credit facility was terminated. There was no indebtedness outstanding or accrued interest payable on such date.

Debt Agreements MEMP Segment

MEMP Revolving Credit Facility & Senior Notes

On December 14, 2011, Memorial Production Operating LLC (OLLC), a wholly-owned subsidiary of MEMP, entered into multi-year $1.0 billion senior secured revolving credit facility with an initial borrowing base of $300.0 million. A sixth amendment to the credit agreement was entered into on September 26, 2013, which among other things: (i) increased the facility from $1.0 billion to $2.0 billion and (ii) increased the borrowing base from $480.0 million to $920.0 million upon the closing of MEMP s $603.0 million acquisition that closed October 1, 2013. On October 10, 2013, borrowing base was automatically reduced by $75.0 million in conjunction with the issuance of additional senior notes as discussed below in accordance with the terms of the credit facility. 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 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 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base 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, MEMP and Finance Corp. completed a private placement of $300.0 million aggregate principal amount of 7.625% senior unsecured notes due 2021 (the Senior Notes). The 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 Senior Notes, and certain immaterial subsidiaries). On May 23, 2013, the Issuers issued an additional $100.0 million aggregate principal amount of the Senior Notes at 102% of par. The 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, commencing November 1, 2013. The Senior Notes are governed by an indenture. The Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The Issuers may also be required to repurchase the 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 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 Issuers, all outstanding 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 Senior Notes may declare all the Senior Notes to be due and payable immediately. The

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Issuers have agreed pursuant to registration rights agreements to file an exchange offer registration statement or, under certain circumstances, a shelf registration statement with respect to the Senior Notes no later than April 17, 2014.

Previous Owner Revolving Credit Facilities (Terminated)

On October 1, 2013, the debt balance then outstanding under the Boaz and Crown revolving credit facilities and all accrued interest was paid off in full and these revolving credit facilities were terminated. On October 1, 2013, the debt balance then outstanding under the Stanolind and Propel Energy revolving credit facilities and all accrued interest was paid off in full by MEMP on behalf of Stanolind and Propel Energy, respectively.

Contractual Obligations

In the table below, we set forth MRD LLC s consolidated and combined contractual obligations as of December 31, 2013. 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.

	Payments Due by Period (in thousands)				
Contractual Obligations	**Total**	**2014**	**2015 - 2016**	**2017 - 2018**	**Beyond 2018**
Revolving credit facility(1)					
MRD Segment	$ 203,100	$	$	$ 203,100	$
MEMP Segment	103,000			103,000	
Estimated interest payments(2)					
MRD Segment	20,242	4,671	9,342	6,229	
MEMP Segment	14,227	3,348	6,695	4,184	
Notes and Second Lien Term Loan(3)					
MRD Segment	973,500	59,700	119,400	794,400	
MEMP Segment	1,100,313	53,375	106,750	106,750	833,438
Asset retirement obligations(4)					
MRD Segment	12,150	90	1,818	2,775	7,467
MEMP Segment	99,619		1,878	6,373	91,368
Decommissioning Trust Agreement(5)					
MRD Segment					
MEMP Segment	12,392	2,042	10,350		
Operating leases					
MRD Segment	16,340	1,840	4,153	5,091	5,256
MEMP Segment	3,985	549	976	410	2,050
Compression services					
MRD Segment	583	572	11		
MEMP Segment	6,507	6,507			
Drilling services					
MRD Segment	20,323	20,323			
MEMP Segment					
Processing Plant Demand Fees					
MRD Segment	118,182	19,347	51,606	47,229	
MEMP Segment					

Total	$ 2,704,463	$ 172,364	$ 312,979	$ 1,279,541	$ 939,579

(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, 2013. In calculating these amounts, we applied the weighted-average interest rate during 2013 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 2013 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, 2013.

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(3) Represents the scheduled future interest payments and principal payments on the PIK notes, the Senior Notes and the WildHorse Resources second lien term loan. 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, 2013 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 Bureau of Ocean Energy Management decommissioning trust agreement, the Partnership is required to fund a trust account to comply with supplemental regulatory bonding requirements related to decommissioning obligations for the offshore Southern California production facilities. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information.

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.

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 use NSAI to prepare a reserve report as of December 31 of each year 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.

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 natural gas and oil 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 to the extent the actual costs differ from the recorded liability.

Incentive Units

The governing documents of MRD LLC and certain of MRD LLC s subsidiaries, including WildHorse Resources and BlueStone, provide for the issuance of incentive units. The incentive units are subject to performance conditions that affect their vesting. Compensation cost is recognized only if the performance condition is probable of being satisfied at each reporting date.

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

Revenue Recognition

Revenue from the sale of natural gas and oil is recognized when title passes, net of royalties due to third parties. Natural gas and oil revenues are recorded using the sales method. Under this method, revenues are recognized based on actual volumes of natural gas and oil 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 that we have an imbalance in excess of our proportionate share of the remaining recoverable reserves on the underlying properties.

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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

Our predecessor is organized as a pass-through entity for federal income tax purposes. As a result, members are responsible for federal income taxes on their share of our taxable income. Certain of our predecessor s consolidated subsidiaries are taxed as corporations and subject to federal income taxes. Our predecessor is 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 taxes arise due to temporary differences between the financial statement carrying value of existing assets and liabilities and their respective tax basis.

Our predecessor must recognize the tax effects of any uncertain tax positions it may adopt if the position taken 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 a 50% chance of being realized. There were no uncertain tax positions that required recognition in the financial statements at December 31, 2013 or 2012.

Upon closing of the offering, we will be treated as a taxable C corporation and will be subject to federal and certain state income taxes. Accordingly, a pro forma income tax provision has been disclosed as if our predecessor was a taxable corporation for all periods presented. A pro forma effective tax rate of 36.06% and 35.39% was used for the years ended December 31, 2013 and 2012, respectively. If MRD LLC had affected the change in tax status on December 31, 2013, MRD LLC would have recognized a deferred tax liability of approximately $114.9 million primarily related to the tax basis of its long-lived assets being less than its book basis in those assets. MRD LLC would not have recognized any material deferred tax assets.

Unaudited Pro Forma Earnings Per Share

MRD LLC has presented pro forma earnings per share for all periods presented. Pro forma net income (loss) per basic and diluted share is determined by dividing the pro forma net income (loss) by the number of common shares expected to be outstanding immediately following the Offering.

Off Balance Sheet Arrangements

As of December 31, 2013, 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.

Emerging Growth Company

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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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 hedging purposes, rather 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 and oil prices. Natural gas 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 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 and oil production through various transactions that fix the future 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. 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. These hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to natural gas and oil price fluctuations. We do not enter derivative contracts for speculative trading purposes. Our 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.

For additional information regarding the volumes of our production covered by commodity derivative contracts and the average prices at which production is hedged as of March 31, 2014, December 31, 2013 and December 31, 2012, see the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus as well as the tables below.

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

	Remaining 2014	2015	2016	2017
Natural Gas Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (MMBtu)	1,706,667	940,000	670,000	520,000
Weighted-average fixed price	$ 4.19	$ 4.19	$ 4.32	$ 4.45
Collar contracts:				
Average Monthly Volume (MMBtu)	730,000	130,000		
Weighted-average floor price	$ 4.11	$ 4.00	$	$
Weighted-average ceiling price	$ 5.15	$ 4.64	$	$
Basis swaps:				
Average Monthly Volume (MMBtu)	270,000	180,000	220,000	200,000
Spread	$ (0.07)	$ (0.09)	$ (0.08)	$ (0.08)
Crude Oil Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	23,333	9,000		
Weighted-average fixed price	$ 92.09	$ 87.36	$	$
Collar contracts:				
Average Monthly Volume (Bbls)	12,000	2,000		
Weighted-average floor price	$ 86.67	$ 85.00	$	$
Weighted-average ceiling price	$ 112.33	$ 101.35	$	$
NGL Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	31,667			
Weighted-average fixed price	$ 64.92	$	$	$

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

	Remaining 2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	2,641,206	2,405,278	2,492,442	2,300,067	2,060,000	1,814,583
Weighted-average fixed price	$ 4.33	$ 4.28	$ 4.41	$ 4.31	$ 4.52	$ 4.77
Collar contracts:						
Average Monthly Volume (MMBtu)	340,000	350,000				
Weighted-average floor price	$ 4.95	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 6.19	$ 5.80	$	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	120,000	80,000				
Weighted-average sold strike price	$ 5.11	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.38	$ 6.75	$	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	2,888,889					
Spread	$ (0.09)	$	$	$	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	174,308	194,281	180,313	166,600	152,000	40,000
Weighted-average fixed price	$ 95.95	$ 91.90	$ 86.05	$ 84.74	$ 84.59	$ 85.00
Collar contracts:						
Average Monthly Volume (Bbls)	23,000	5,000				
Weighted-average floor price	$ 82.83	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 105.31	$ 94.00	$	$	$	$
Basis swaps:						
Average Monthly Volume (Bbls)	93,667	57,500				
Spread	$ (4.57)	$ (9.73)	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	136,200	112,800				
Weighted-average fixed price	$ 36.33	$ 35.04	$	$	$	$

(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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At December 31, 2013, the MRD Segment had the following open commodity positions:

	2014	2015	2016	2017
Natural Gas Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (MMBtu)	1,190,000	880,000	670,000	520,000
Weighted-average fixed price	$ 4.10	$ 4.19	$ 4.32	$ 4.45
Collar contracts:				
Average Monthly Volume (MMBtu)	330,000	130,000		
Weighted-average floor price	$ 4.09	$ 4.00	$	$
Weighted-average ceiling price	$ 5.24	$ 4.64	$	$
Basis swaps:				
Average Monthly Volume (MMBtu)	270,000	180,000	220,000	200,000
Spread	$ (0.07)	$ (0.09)	$ (0.08)	$ (0.08)
Crude Oil Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	18,000	6,000		
Weighted-average fixed price	$ 91.66	$ 88.50	$	$
Collar contracts:				
Average Monthly Volume (Bbls)	8,000	2,000		
Weighted-average floor price	$ 85.00	$ 85.00	$	$
Weighted-average ceiling price	$ 117.50	$ 101.35	$	$
NGL Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	18,000			
Weighted-average fixed price	$ 64.27			

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At December 31, 2013, the MEMP Segment had the following open commodity positions:

	2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	2,575,458	2,145,278	2,342,442	2,230,067	2,060,000	1,814,583
Weighted-average fixed price	$ 4.34	$ 4.30	$ 4.42	$ 4.31	$ 4.52	$ 4.77
Collar contracts:						
Average Monthly Volume (MMBtu)	340,000	350,000				
Weighted-average floor price	$ 4.93	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 6.12	$ 5.80	$	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	120,000	80,000				
Weighted-average sold strike price	$ 5.08	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.31	$ 6.75	$	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	2,822,083					
Spread	$ (0.09)	$	$	$	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	136,444	148,281	142,313	130,600	122,000	40,000
Weighted-average fixed price	$ 95.82	$ 93.07	$ 86.85	$ 85.96	$ 85.62	$ 85.00
Collar contracts:						
Average Monthly Volume (Bbls)	23,000	5,000				
Weighted-average floor price	$ 82.83	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 105.31	$ 94.00	$	$	$	$
Basis swaps:						
Average Monthly Volume (Bbls)	57,292	57,500				
Spread	$ (9.21)	$ (9.73)	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	118,500	112,800				
Weighted-average fixed price	$ 36.23	$ 35.04	$	$	$	$

(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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At December 31, 2012, the MRD Segment had the following open commodity positions:

	2013	2014	2015
Natural Gas Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (MMBtu)	961,000	540,000	210,000
Weighted-average fixed price	$ 4.08	$ 3.96	$ 4.09
Collar contracts:			
Average Monthly Volume (MMBtu)	661,000	430,000	130,000
Weighted-average floor price	$ 4.61	$ 4.18	$ 4.00
Weighted-average ceiling price	$ 5.56	$ 5.10	$ 4.64
Basis swaps:			
Average Monthly Volume (MMBtu)	230,000	230,000	390,000
Spread	$ (0.09)	$ (0.09)	$ (0.09)
Crude Oil Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (Bbls)	6,000		
Weighted-average fixed price	$ 98.44	$	$
Collar contracts:			
Average Monthly Volume (Bbls)	22,750	14,000	2,000
Weighted-average floor price	$ 84.66	$ 87.86	$ 85.00
Weighted-average ceiling price	$ 108.89	$ 111.34	$ 101.35
NGL Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (Bbls)	28,500	2,000	
Weighted-average fixed price	$ 54.12	$ 84.00	$

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At December 31, 2012, the MEMP Segment had the following open commodity positions:

	2013	2014	2015	2016	2017	2018
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	1,017,672	1,462,125	1,156,112	1,113,275	1,020,067	900,000
Weighted-average fixed price	$ 4.35	$ 4.38	$ 4.28	$ 4.53	$ 4.30	$ 4.75
Collar contracts:						
Average Monthly Volume (MMBtu)	1,014,000	340,000	350,000			
Weighted-average floor price	$ 4.76	$ 4.93	$ 4.62	$	$	$
Weighted-average ceiling price	$ 5.82	$ 6.12	$ 5.80	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	430,000	120,000	80,000			
Weighted-average sold strike price	$ 4.59	$ 5.08	$ 5.25	$	$	$
Weighted-average bought strike price	$ 5.84	$ 6.31	$ 6.75	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	813,432	1,318,750				
Spread	$ (0.11)	$ (0.09)	$	$	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	70,632	35,102	12,031	11,013	10,000	
Weighted-average fixed price	$ 103.32	$ 94.27	$ 90.29	$ 90.39	$ 88.30	$
Collar contracts:						
Average Monthly Volume (Bbls)	36,750	52,158	50,000	44,000	42,000	
Weighted-average floor price	$ 84.73	$ 90.51	$ 89.00	$ 85.00	$ 85.00	$
Weighted-average ceiling price	$ 108.07	$ 107.03	$ 103.31	$ 103.40	$ 99.00	$
Call contracts:						
Average Monthly Volume (Bbls)	10,000					
Weighted-average fixed price	$ 115.00	$	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	30,805	16,300				
Weighted-average fixed price	$ 53.19	$ 58.91	$	$	$	$

(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.

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. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information regarding fixed-for-floating interest rate swap open positions as of March 31, 2014, December 31, 2013 and December 31, 2012 as well as the tables below.

At March 31, 2014, we had the following interest rate swap open positions:

Credit Facility	2015	2016

	Remaining 2014		
MEMP:			
Average Monthly Notional (in thousands)	$ 214,778	$ 280,833	$ 150,000
Weighted-average fixed rate	1.316%	1.416%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR
WildHorse Resources:			
Average Monthly Notional (in thousands)	$ 116,667	$ 100,000	$
Weighted-average fixed rate	0.772%	0.758%	
Floating rate	1 & 3 Month LIBOR	1 & 3 Month LIBOR	

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At December 31, 2013, we had the following interest rate swap open positions:

Credit Facility		2014		2015		2016
MEMP:						
Average Monthly Notional (in thousands)	$	173,958	$	280,833	$	150,000
Weighted-average fixed rate		1.306%		1.416%		1.193%
Floating rate		1 Month LIBOR		1 Month LIBOR		1 Month LIBOR
WildHorse Resources:						
Average Monthly Notional (in thousands)	$	118,750	$	100,000	$	
Weighted-average fixed rate		0.773%		0.758%		
Floating rate		1 Month LIBOR		1 Month LIBOR		

At December 31, 2012, we had the following interest rate swap open positions:

Credit Facility		2013		2014		2015		2016
MEMP:								
Average Monthly Notional (in thousands)	$	162,500	$	150,000	$	150,000	$	150,000
Weighted-average fixed rate		1.148%		1.193%		1.193%		1.193%
Floating rate		1 Month LIBOR		1 Month LIBOR		1 Month LIBOR		1 Month LIBOR
WildHorse Resources:								
Average Monthly Notional (in thousands)	$	150,667	$	118,750	$	100,000	$	
Weighted-average fixed rate		0.779%		0.773%		0.758%		
Floating rate		1 Month LIBOR		1 Month LIBOR		1 Month LIBOR		
Tanos:								
Average Monthly Notional (in thousands)	$	30,000	$		$		$	
Weighted-average fixed rate		1.362%						
Floating rate		1 Month LIBOR						
WHT:								
Average Monthly Notional (in thousands)	$	75,000	$	25,000	$		$	
Weighted-average fixed rate		1.510%		1.510%				
Floating rate		1 Month LIBOR		1 Month LIBOR				
Previous Owners:								
Average Monthly Notional (in thousands)	$	11,500		5,750	$		$	
Weighted-average fixed rate		0.500%		0.500%				
Floating rate		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 March 31, 2014, our derivative contracts are with major financial institutions, certain of which are also lenders under our revolving credit facilities. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information.

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

MRD LLC has two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

MRD reflects all of MRD LLC s consolidating subsidiaries except for MEMP.

MEMP reflects the consolidated and combined operations of MEMP.

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 own a minority of its partner interests. As a result, our financial statements and notes thereto included elsewhere in this prospectus consolidate MEMP s business and assets with ours. However, 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. See MEMP for information regarding MEMP s business and assets. In addition, because BlueStone will not be included in the assets that MRD LLC will contribute to us in connection with the restructuring transactions, unless stated otherwise, the information in this section does not include BlueStone.

We are an independent natural gas and oil company focused on the exploitation, development, and acquisition of natural gas, NGL 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. Our total leasehold position is 347,458 gross (205,818 net) acres, of which 60,041 gross (51,522 net) acres are in what we believe to be the core of the Terryville Complex. We are focused on creating shareholder value primarily through the development of our sizeable horizontal inventory.

MEMP 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 principally located in East Texas/North Louisiana, the Permian Basin, offshore Southern California, the Rockies, the Eagle Ford and South Texas. 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. 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.

MRD

Overview

As of December 31, 2013, we had 1,582 gross (1,091 net) identified horizontal drilling locations, of which 1,431 gross (994 net) identified horizontal drilling locations are located in the Terryville Complex. These total net identified horizontal drilling locations represent an inventory of over 32 years based on our expected 2014 drilling program. We believe our inventory to be repeatable and capable of generating high returns based on the extensive production history in the area, the results of our horizontal wells drilled to date, and the consistent reservoir quality across multiple target formations. As of December 31, 2013, we had estimated proved, probable and possible reserves of approximately 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe, respectively. As of such date, we operated 98% of our proved reserves, 71% of which were natural gas. For the three months ended March 31, 2014, 52% of our pro forma MRD Segment revenues were attributable to natural gas production, 24% to NGLs and 24% to oil. For the three months ended March 31, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $67 million and pro forma net income of $15.9 million, and made pro forma capital expenditures of $83 million. For the year ended December 31, 2013, we generated pro forma MRD Segment Adjusted EBITDA of $159 million and pro forma net income of $11.8 million, and made pro forma total capital expenditures of $203 million. Please see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA for an explanation of the basis for the pro forma presentation and our use of Adjusted EBITDA to measure the MRD Segment s profitability.

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Our average net daily production for the three months ended March 31, 2014 was 168 MMcfe/d (approximately 70% natural gas, 21% NGLs and 9% oil) and our reserve life was 18 years. As of December 31, 2013, we produced from 95 horizontal wells and 800 vertical wells. The Terryville Complex represented 85% of our total net production for the three months ended March 31, 2014. Our estimated average net daily production for the period from April 1 through April 30, 2014 was 179 MMcfe/d, of which 73% was from natural gas. Our estimated average net daily production from our properties in the Terryville Complex for the same period was 141 MMcfe/d, or 79% of our total production. In the Terryville Complex, we have completed and brought online six additional horizontal wells since January 1, 2014, bringing our total number of producing horizontal wells to 27 in our primary formations. The 30 day production average rates of our four most recent wells averaged 25.1 MMcfe/d per well.

The following chart provides information regarding our production growth and the increasing proportion of our horizontal well production since the beginning of 2012.

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. To date, operators have drilled over 600 horizontal Cotton Valley wells. Some large, analogous redevelopment projects in the Cotton Valley include the Nan-Su-Gail Field in Freestone County, East Texas, where over 40 horizontal wells have been drilled by operators such as Devon Energy Corporation and Marathon Oil Corporation, and the Carthage Complex in Panola County, East Texas, where operators such as ExxonMobil Corporation, BP America, Memorial Production Partners LP and Anadarko Petroleum Corporation have drilled over 153 horizontal wells.

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Cotton Valley Terryville Complex Horizontal Redevelopment

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 60,041 gross (51,522 net) acres as of December 31, 2013. The majority of our current and planned development is focused in and around what we believe to be the core of the Terryville Complex.

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 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. We intend to dedicate approximately $264 million of our $312 million drilling and completion budget in 2014 to develop multiple zones within the Terryville Complex, where we expect to drill and complete 35 gross (30 net) wells. Our horizontal redevelopment program in the Terryville Complex will be focused on increasing our well performance and recoveries.

Within the Terryville Complex, as of December 31, 2013, we had 945 Bcfe, 688 Bcfe and 1,643 Bcfe of estimated proved, probable and possible reserves, respectively, and a drilling inventory consisting of 1,431 gross (994 net) identified horizontal drilling locations, including 91 gross (72 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. Since initiating our horizontal drilling program in 2011, we have drilled 27 gross (22.0 net) horizontal wells, growing our gross daily production in the Terryville Complex by 304% from 53.0 MMcfe/d for the three months ended March 31, 2010 to 214.0 MMcfe/d for the month ended April 30, 2014. For the three months ended March 31, 2014, 51% of our revenues from the Terryville Complex were attributable to natural gas, 25% to NGLs and 24% to oil. Within the Terryville Complex, on a proved reserves basis, we operate approximately 99% of our existing acreage and hold an average working interest of approximately 74% across our acreage. Our high operating control allows us to more efficiently and economically manage the redevelopment of this extensive resource.

We believe seismic data, as well as information gathered from the results of our existing 275 vertical and 27 horizontal wells throughout the field, support the existence of at least ten stacked pay zones across the Terryville Complex. Our redevelopment program currently targets four of the stacked 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 400 to 890 feet across our acreage position. We believe the overpressured nature of this section of the Cotton Valley formation is highly productive when accessed through horizontal drilling and fracture stimulation technologies. These qualities, when combined with the liquids-rich nature of the natural gas, high initial rates of production and competitive well costs, produce what we believe to be amongst the highest rate of return wells in the nation. Further, there are additional opportunities for redevelopment in the zones above the four main zones. NSAI has allocated over $1 billion PV-10 and 677 Bcfe to our possible reserve category for the redevelopment of these additional zones. Please see Reserves.

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The table below details certain information on estimated ultimate recoveries and production for the 27 horizontal wells currently producing in the Terryville Complex. Our well results have shown consistency in initial production, decline rates and estimated ultimate recovery. The consistency of these results gives us confidence that the full-scale redevelopment of the Terryville Complex we began in 2013 will be successful as we move from four to five rigs in 2014.

		Producing Wells EUR(2)							Cumulative Production				Gross Wellhead Flow Rates After Processing (MMcfe/d)(3)(4)				
Well Name(1)	**Lateral Length (Feet)**	**Bcfe**	**%Gas**	**%NGL**	**%Oil**	**EUR Bcfe/ 1,000**	**First Production**	**Days Producing**	**Bcfe**	**%Gas**	**%NGL**	**%Oil**	**0-30**	**0-90**	**91-180**	**181-360**	**D&C ($MM)**
Upper Red Zone																	
LD Barnett 23H-2	4,015	13.6	69%	27%	4%	3.4	1/30/2012	842	4.6	71%	24%	5%	14.5	12.0	7.7	5.6	6.7
Colquitt 20 17H-1	4,357	11.2	80%	18%	2%	2.6	7/30/2012	660	3.9	82%	17%	2%	17.5	12.6	7.2	5.1	7.7
Dowling 22 15H-1	5,376	16.8	75%	23%	2%	3.1	9/22/2012	606	5.2	80%	18%	3%	16.3	15.6	11.1	8.2	8.8
Nobles 13H-1	4,216	11.6	66%	23%	11%	2.8	11/17/2012	550	4.3	66%	21%	13%	21.5	16.7	9.9	6.5	7.8
Sidney McCullin 16 21H-1	4,604	16.9	75%	22%	2%	3.7	1/19/2013	487	4.5	81%	16%	3%	17.4	14.2	10.8	8.4	8.1
Wright 14 11 HC-1	5,250	18.0	68%	26%	6%	3.4	5/27/2013	359	4.6	65%	28%	8%	19.6	18.1	16.1	8.5	8.8
BF Fallin 22 15H-1	5,122	15.6	73%	24%	3%	3.0	6/17/2013	338	3.2	74%	22%	4%	14.8	13.7	11.8		7.5
Dowling 20 17H-1	4,327	8.9	73%	25%	2%	2.1	7/22/2013	303	2.1	77%	20%	3%	15.2	11.0	5.7		10.7
Gleason 31H-1	3,692	2.5	92%	8%		0.7	8/12/2013	282	0.5	92%	8%		3.5	2.7	1.8		9.4
Burnett 26H-1	2,405	4.2	71%	25%	4%	1.7	9/22/2013	241	0.9	70%	26%	4%	6.9	5.5	3.3		6.6
Drewett 17 8H-1	4,010	14.0	67%	23%	10%	3.5	11/13/2013	189	2.9	61%	28%	11%	22.1	18.7	12.3		7.7
Wright 13 12 HC-2	6,009	18.1	69%	23%	8%	3.0	12/21/2013	151	2.7	78%	10%	12%	22.7	19.5			8.0
LA Minerals 15 22H-2	5,814	N/A				N/A	1/21/2014	120	1.9				18.1	16.7			9.3
TL McCrary 14 11 HC-5	5,875	N/A				N/A	4/14/2014	37	0.9				25.3				7.8
Wright 13 24 HC-1	6,678	N/A				N/A	4/14/2014	37	0.8				23.2				8.9
Wright 13 24 HC-3	6,606	N/A				N/A	4/14/2014	37	1.0				28.1				7.6
Lower Red Zone																	
TL McCrary 14H-1	4,544	12.8	70%	27%	3%	2.8	5/1/2012	750	4.0	73%	23%	4%	14.4	11.7	8.3	5.4	7.7
Nobles 13H-2	4,060	9.2	70%	25%	5%	2.3	11/17/2012	550	3.1	69%	22%	8%	16.0	11.9	8.4	5.2	7.8
LA Methodist Orphanage 14H-1	3,637	12.1	70%	24%	6%	3.3	2/15/2013	460	3.6	70%	22%	8%	13.9	13.0	9.7	6.3	9.1
Dowling 21 16H-1	4,590	9.4	77%	21%	1%	2.0	3/18/2013	429	2.6	84%	14%	2%	13.0	10.1	6.5	4.5	6.6
Drewett 17 8H-2	3,700	3.7	69%	24%	7%	1.0	11/13/2013	189	0.9	64%	29%	7%	8.7	6.2	3.2		6.8
Wright 13 12 HC-1	5,409	8.2	68%	22%	10%	1.5	12/21/2013	151	1.5	77%	10%	13%	14.7	11.3			9.1
LA Minerals 15 22H-1	5,926	N/A				N/A	1/21/2014	120	1.2				13.8	11.1			8.0
Wright 13 24 HC-4	6,518	N/A				N/A	4/14/2014	37	0.8				23.8				10.3
Lower Deep Pink Zone																	
LA Methodist Orphanage 14H-2	3,550	12.2	68%	24%	8%	3.4	2/15/2013	460	3.2	68%	21%	10%	14.2	11.6	7.6	5.6	6.1
Wright 13 12 HC-3	5,706	6.3	69%	23%	8%	1.1	12/21/2013	151	1.2	79%	10%	12%	12.5	9.3			7.1
Wright 13 12 HC-4	5,010	5.0	69%	22%	9%	1.0	12/21/2013	151	1.1	78%	10%	12%	11.8	8.8			6.1

Averages																
All Wells	**4,852**	**11.0**	**72%**	**23%**	**5%**	**2.5**	**322**	**2.5**	**74%**	**19%**	**7%**	**16.4**	**12.3**	**8.3**	**6.3**	**8.0**
Upper Red	**4,897**	**12.6**	**73%**	**22%**	**5%**	**2.7**	**327**	**2.8**	**75%**	**20%**	**6%**	**17.9**	**13.6**	**8.9**	**7.0**	**8.2**
Lower Red	**4,798**	**9.2**	**71%**	**24%**	**5%**	**2.2**	**336**	**2.2**	**73%**	**20%**	**7%**	**14.8**	**10.8**	**7.2**	**5.4**	**8.2**
Lower Deep Pink																